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NATURAL GAS SUPPLY AND DELIVERABILITY

HEARING

BEFORE THE

SUBCOMMITTEE ON MINERAL RESOURCES
DEVELOPMENT AND PRODUCTION

OF THE

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

ONE HUNDRED FIRST CONGRESS

FIRST SESSION

ON

NATURAL GAS SUPPLY AND DELIVERABILITY

SEPTEMBER 26, 1989

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NATURAL GAS SUPPLY AND DELIVERABILITY

TUESDAY, SEPTEMBER 26, 1989

U.S. SENATE,
SUBCOMMITTEE ON MINERAL RESOURCES
DEVELOPMENT AND PRODUCTION,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The subcommittee met, pursuant to notice, at 2:20 p.m., in room SD-366, Dirksen Senate Office Building, Hon. Jeff Bingaman, presiding.

OPENING STATEMENT OF HON. JEFF BINGAMAN, U.S. SENATOR FROM NEW MEXICO

Senator BINGAMAN. Good afternoon.

This is an oversight hearing of the Mineral Resources Development and Production Subcommittee.

The hearing today is intended to explore what the supply and demand relationship for natural gas will look like after 1990.

The question takes on particular significance because I believe that the natural gas industry and the end-use markets served by natural gas are poised on the edge of a significant transition; namely, the transition from a period of excess production capacity that has defined the industry and the market for much of the 1980s, widely known as the gas bubble, to a period when supply and demand for natural gas will be in greater balance and when there will be a potentially, at least, significant new demand for natural gas.

For much of this year, a debate has taken shape within the natural gas industry and among analysts who follow the industry over whether this transition will be a so-called hard landing or a smooth landing.

Today the subcommittee has assembled experts from the United States Department of Energy, from within the natural gas industry, and from among analysts who follow the industry, to share with us their thoughts on this issue.

The focal point of the hearing will be a debate or discussion on natural gas supply and deliverability issues between two of the leading actors in the hard landing versus soft landing debate: Mr. John Sawhill of McKinsey & Company, who served with great distinction as a federal energy official in the Ford and Carter Administrations; and Mr. Ken Lay of Enron Corporation.

Also with us today as a witness on the subsequent panel is another leading player in the industry dialogue on this topic, Mr. Bud Lawrence of the American Gas Association.

We are also very honored to have with us today as our first witness, the Hon. Henson Moore, who is the Deputy Secretary of the Department of Energy.

Considering the format that we have laid out today, I would encourage witnesses to summarize their statements. Obviously, the entire statements of any witness will be included in the record of the hearing, and the hearing record will remain open for an additional two weeks.

I look forward to what I believe will be a very informative hearing.

We have other members of the committee who have indicated a desire to be here for today's hearing; unfortunately, we have just completed a vote on the floor. But I am sure some of those members will come in and may have statements to give later in the hearing.

At this time let me defer to Deputy Secretary Henson Moore for his testimony in telling us the administration's point of view on these important issues.

I am very pleased that you are able to be here today. I know there are a few other items pending before the Department of Energy besides this hearing, so we are very glad you are here.

[The prepared statement of Senator Bingaman follows:]

OPENING STATEMENT
OF
SENATOR JEFF BINGAMAN

OVERSIGHT HEARING ON
NATURAL GAS SUPPLY AND DELIVERABILITY
UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
SUBCOMMITTEE ON MINERAL RESOURCES DEVELOPMENT AND PRODUCTION

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The focal point of our hearing will be a debate on natural gas supply and deliverability issues between two of the leading actors in the "hard landing" versus "smooth landing" debate. The debate will feature Mr. John Sawhill of McKinsey & Company, who served with great distinction as a federal energy official in the Ford and Carter Administrations, and Mr. Ken Lay of Enron Corporation. Also with us today as a witness on the subsequent panel is another leading player in the industry dialogue on this topic, Mr. Bud Lawrence of the American Gas Association.

We are also honored to have with us today as our first witness, the Honorable Henson Moore, Deputy Secretary of the United States Department of Energy.

Considering the format of this hearing, I ask that you please limit your oral remarks to no more than 5 minutes. Your entire written statement will be made a part of the hearing record. At this time, I will place copies of both measures in the hearing record.

The hearing record will remain open for two weeks for additional comments and additional statements that people may want to submit in writing.

I look forward to what should be a very interesting and informative hearing.

In a matter directly related to the role that natural gas can play in the 1990s, I would like to announce that, along with Senator Ford, I intend later this week to introduce legislation to promote the deployment of cofiring technologies. Cofiring involves the combined use of coal and natural gas as boiler fuel in electric generating plants and industrial facilities. Cofiring technology can reduce emissions of sulfur dioxide, nitrogen oxides and carbon dioxide in a cost-effective manner. Cofiring is a prime example of the role that natural gas can play in achieving the emissions reductions that the Congress is considering in legislation to reauthorize the Clean Air Act.

Before we begin with Deputy Secretary Moore's testimony, do any of my colleagues have opening statements for the record?

STATEMENT OF W. HENSON MOORE, DEPUTY SECRETARY, DEPARTMENT OF ENERGY

Mr. MOORE. Thank you, Mr. Chairman.

Certainly nothing is more important to us than the future of the natural gas industry. We compliment you on having this hearing. We are glad to be here.

I will submit for the record the lengthy and full statement, which will go into a great deal more detail than my oral comments.

Let me say that five years ago, even three years ago, it would have been difficult to predict that in the 1990s, the natural gas industry would finally be ready and able to make a major contribution to a sound energy future for America.

We think that is the case.

To the extent that environmental pressures present us with a problem, natural gas can help because of its clean-burning properties. To the extent that we need to develop new supplies of electricity, new natural gas turbine technology offers significant advantages. To the extent that we consider new options for transportation fuels, compressed natural gas may play a significant role.

Passage of the Wellhead Decontrol Act of 1989 represented a bipartisan achievement of the Bush Administration's first major energy initiative and was a major move forward toward our goal of a more stable domestic energy future.

I would like to thank those members of Congress on both sides of the aisle, who worked so hard to achieve enactment of that legislation. But, there is much more, we think, that can be done to ensure that natural gas reaches its full potential.

To assess the potential for natural gas, we first need to assess the size of the domestic resource base. Having done an assessment in DOE, we think that there is plenty of natural gas.

Both the DOE study and the recently released Department of Interior report support DOE's view that the United States has enough gas to take us well into the middle of the next century at reasonable prices.

With an abundant resource base and the recent legislation providing for the near-term decontrol of natural gas wellhead prices, prospects for the industry, for the most part, are bright.

Consumption in 1988 was 17.9 trillion cubic feet, which represents an increase of about 10 percent from 1986 consumption.

Although natural gas spot prices remain low, the combination of increasing demand and reduced finding costs has encouraged more gas drilling. The gas rig count is up nearly 100 over this time a year ago, and EIA recently reported that U.S. total discoveries of dry gas were up 44 percent to 10.35 trillion cubic feet in 1988, the highest level since 1985.

At the National Energy Strategy hearing that we held in Tulsa, Oklahoma on August 8th, 1989, a distinguished panel made up of Governor Clements of Texas, and Senators Boren and Nickles of Oklahoma, discussed at length the potential for natural gas to make a larger contribution to satisfy our national energy needs. However, they also noted problems with the current gas industry.

We have made the major changes necessary to accomplish the first generation of natural gas regulatory and statutory reforms:

repeal of the Fuel Use Act, non-discriminatory transportation by natural gas pipelines, and wellhead decontrol. We must now develop a second generation of natural gas statutory and regulatory reform.

I want briefly to discuss our proposals for that agenda, that second wave of decontrol. Basically, there are three parts to it.

First, we think it takes too long and it is too difficult to build the new pipeline capacity we need to provide expanded, more competitive and more efficient service. The pipeline industry is not the infant industry that existed in 1938, but a very mature, multi-billion dollar transportation business. To be competitive, the gas pipeline industry must be able to respond efficiently and decisively; pipeline capacity must be available to serve new customers and to connect the new reserves.

I believe it is time for us to reexamine the 50-year-old regulatory process required for gas pipeline construction. I recognize that removing barriers to entry in the natural gas industry is no simple undertaking. What I am suggesting today is that it is time for us to work together on creating solutions so that pipeline certification is not a barrier to a flexible and efficient natural gas transmission network.

Getting the capacity when and where it is needed is only half the battle. We need pipeline rate design that encourages the most efficient utilization of existing facilities. Many pipelines have capacity constraints in the winter months when demand is at its peak. In many cases, the development of additional storage could allow peak needs to be met without building more costly pipeline capacity. This new storage will not be built and used, however, unless there are economic incentives to do so.

FERC is moving to correct these rate design problems. I raise the issues here to demonstrate the importance in achieving a more flexible, responsive natural gas industry, and so that all of us take a look at that problem.

The passage of the Wellhead Decontrol Act of 1989 signalled an impending end to 35 years of counterproductive regulation. Unfortunately, this regulation is dying, not with a whimper, but with a bang.

On September 15th, the U.S. Court of Appeals for the Fifth Circuit reversed FERC's Order 451, the Order raising the ceiling price on old gas.

The DOE strongly supports Order 451 and disagrees with the court's decision. This decision is troublesome for several reasons.

First, it may prevent FERC from considering needed reforms not only in producer regulation, but in the regulation of oil and gas pipelines and electric utilities.

Second, the uncertainty and possible refund liability created by this decision could have an adverse impact on drilling investments and natural gas deliverability.

Lastly, it may necessitate lengthy and complicated proceedings at FERC. If far-reaching orders are totally reversed three years after full implementation, industry will find it impossible to respond to necessary regulatory-induced changes.

We intend to recommend that FERC and the Justice Department seek further judicial review of this court decision. In addition to rectifying this court decision, the third area we would like to look into, as part of the second generation of natural gas deregulation issues, is the further action that will free natural gas to move to the market.

Current policy creates barriers, preventing the largest and most experienced buyers of gas, natural gas pipelines, from participating effectively in the gas market. Pipelines are still forced to charge customers not the market price for gas, but a price based on complex accounting and contractual arrangements that may have been made decades earlier.

All other sellers of gas price their gas in accordance with the market and whatever private contractual arrangements that have been negotiated. It is time to question whether continued Federal regulation of pipeline gas prices is appropriate.

These are the three areas that we have identified at the Department of Energy in the early months of the Bush Administration. They are worthy of review by the Congress, by the Department of Energy and by FERC, in terms of a second generation of efforts to further deregulate the natural gas market.

We will be looking at all three of these issues in the National Energy Strategy that we are working on now.

Mr. Chairman, and Members of this committee, this gas industry of ours is a truly remarkable thing. It was given up for dead a few years ago. It was written off by customers looking for cheap and reliable fuel. But today we see this industry from a new vantage point. We have learned. We removed many of the unnecessary barriers and the industry became vibrant again.

Now we need to finish the job we started.

The benefits to both the gas industry and to the Nation are well worth the effort. If we are successful, I believe that natural gas can reach its full potential as one of the key components in meeting our national energy and environmental goals in the future. But we still have some work to do.

Thank you.

[The prepared statement of Mr. Moore follows:]

STATEMENT OF W. HENSON MOORE

DEPUTY SECRETARY OF ENERGY

before the

SUBCOMMITTEE ON MINERAL RESOURCES
DEVELOPMENT AND PRODUCTION

COMMITTEE ON ENERGY AND NATURAL RESOURCES

U.S. SENATE

September 26, 1989

Good afternoon. Mr. Chairman, I appreciate the opportunity to appear before this Committee to discuss the Department of Energy's view of the future of the natural gas industry. My testimony today will discuss how the gas industry has changed and will identify additional statutory and regulatory roadblocks that the Department of Energy thinks should be removed in order to allow natural gas to reach its full potential as a reliable, clean source of energy for decades to come.

THE TRANSFORMATION OF THE NATURAL GAS INDUSTRY

During the 1980's, the natural gas industry has been profoundly transformed. Both the industry and its regulators have come to understand that producing and supplying natural gas is a competitive business.

Prior to the 1980's, government policymakers thought that our Nation's supply of gas was acutely limited. They also thought that all parts of the natural gas industry, including producers, should be treated as if they were public utilities. We now know that government regulation produced the "shortages" of natural gas that occurred in the 1970's. We in government must ensure that we do not repeat those past mistakes.

Five years ago, even three years ago, it would have been difficult to predict that in the 1990's the natural gas industry would be ready and able to make a major contribution to a sound energy future for America. Happily, today that is the case. To the extent that environmental pressures present us with a problem, natural gas can help because of its clean-burning properties. To the extent that we need to develop new supplies of electricity, new natural gas turbine technology offers significant advantages. To the extent that we consider new options for transportation fuels, compressed natural gas may play a significant role.

Passage of the Wellhead Decontrol Act of 1989 represented the bipartisan achievement of the Bush Administration's first major energy initiative and was a major move forward toward our goal of a more stable domestic energy future. I would like to thank those members of Congress, on both sides of the aisle, who worked so hard to achieve enactment of that legislation. But, there is more that can be done to ensure that natural gas reaches its full potential.

ADEQUACY OF SUPPLY

To assess the potential for natural gas, we first need to assess the size of the domestic resource base. In the past, there has been some confusion about the extent of the gas resource base and its economic recoverability. Reports that we have a large quantity of gas were published along with reports that we were running out of gas. The result was public confusion and difficulty in making informed fuel choices. This has been detrimental to the healthy development of the natural gas industry, which depends upon consumer confidence that the supply will be there.

Because of all this, the Department of Energy conducted a study to assess the natural gas resource base in the United States. That study, published in May 1988, concluded that the Nation has large supplies of gas. The bottom line of the report was that at current levels of consumption (18 trillion cubic feet (tcf) annually), the Nation has a 35-year supply of natural gas at costs of less than $3.00 per thousand cubic feet in 1987 dollars at the wellhead. This result is particularly significant because it represents a consensus of the Nation's leading gas resource specialists on the extent of our gas resource base and its economic recoverability.

Just this past summer, the U.S. Geological Survey and Minerals Management Service of the Department of Interior (DOI) released a joint report supporting DOE's view that the United States has enough gas to take us well into the middle of the next century at reasonable prices. DOI estimated that there are 307 to 507 tcf of undiscovered conventional natural gas resources in the U.S. These "undiscovered resources" are in addition to proved reserves of natural gas, which the Department of Energy's Energy Information Administration (EIA) recently assessed at 168 tcf.

It is important to note that DOI has estimated only that portion of the conventional resource base recoverable with conventional technology. This is not the total domestic gas resource available. New unconventional technologies already in use, such as horizontal drilling and enhanced oil and gas recovery, will significantly increase the amount of natural gas resources that we can recover economically. Additionally, unconventional resources such as coal bed methane, Devonian shale, and tight sands gas, will be increasingly available. Moreover, there are 126 tcf of gas estimated to be available in Alaska, when the market price of natural gas in the lower 48 States justifies construction of the facilities required to bring that gas to market.[1]

Some analysts are concerned when they compare the current level of proved natural gas reserves to historic levels. During the last decade, there has been a decrease in proved natural gas reserves from over 200 tcf to less than 170 tcf. Concern is raised that this number is too low by historical standards. I believe, however, that this concern is misplaced.

Contrary to popular opinion, current reserve to current production ratios (R/P) have not in fact declined over the last decade for the Lower 48 States. In 1977, the R/P ratio was 9.4 and in 1988 it was 9.8. R/P ratios have remained relatively flat, however, partly because of a decrease in demand.

Looking beyond the U.S. resource base, many other sources of natural gas are available to the United States. We currently import about 7% of our natural gas from Canada and also import small, but growing quantities of liquefied natural gas (LNG) from Algeria. Imports of gas from Mexico, Norway or other foreign sources are also possibie.

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[1] Beginning with its 1988 Annual Report on reserves, the Energy Information Administration will no longer classify 25 tcf of Alaskan resources as proved reserves since it is not now economic to bring it to market.

PROSPECTS FOR THE INDUSTRY

With an abundant resource base and the recent legislation providing for the near-term decontrol of natural gas wellhead prices, prospects for the industry, for the most part, are bright.

Consumption in 1988 was 17.9 tcf, which represents an increase of about 10% from 1986 consumption. Although natural gas spot prices remain low (the composite spot wellhead price for the second week of September 1989 was $1.43 per MMBtu[2]), the combination of increasing demand and reduced finding costs has encouraged more gas drilling. The gas rig count is up nearly 100 over this time a year ago. As a consequence of this increased drilling activity, the EIA recently reported that U.S. total discoveries of dry gas (those attributable to extensions, new fields, and new reservoirs in old fields) were up 44 percent to 10.35 tcf in 1988, the highest level since 1985. Exploitation of coal bed methane is playing an important role in this expansion.

Most analysts forecast increased consumption of natural gas through the year 2000. The EIA forecasts significantly higher consumption, 20.5 tcf, in the year 2000, an increase of almost 15% over the 1988 consumption level.

The demand for natural gas will be influenced by the answers to a number of significant questions.

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[2] Natural Gas Week.

Will continued low prices and an improved regulatory environment lead to higher demand?

Will compressed natural gas find a niche as a transportation fuel?

How much switching to natural gas from coal and oil will there be?

How much will the use of gas as a fuel for electric generation increase?

Will OPEC decide to increase market share and adopt a strategy of very low oil prices?

Will gas prices increase dramatically and depress natural gas demand below current levels?

Will there continue to be regulatory barriers that make buying natural gas more difficult than buying its competitors (oil, coal, or electricity) or engaging in conservation?

Will the U.S. economy continue to grow at its current rate?

We are addressing all these questions as we develop the National Energy Strategy that the President directed the Department to prepare when he signed the Natural Gas Wellhead Decontrol Act of 1989. It already is clear, however, that our goal should not be to fixate on one view of gas consumption, but to put in place policies that allow the industry to make quick adjustments to ANY demand scenario that develops. This is why we must identify and remove obstacles to gas industry flexibility.

CONTINUE TO REMOVE IMPEDIMENTS

FERC has done yeoman's work in reforming regulations under the 1938 Natural Gas Act and the Natural Gas Policy Act of 1978. Congress also has done its part, enacting wellhead decontrol legislation and repealing most of the Powerplant and

Industrial Fuel Use Act. With these developments alone, the gas industry is stronger and more market responsive than it was ten years ago.

Three developments indicate, however, that there are still statutory and regulatory barriers impeding the U.S. gas market.

First, despite its ample resource base, the U.S. is one of the few countries in the world that produced less gas in 1988 than it did in 1973. U.S. production had decreased by 22% between 1973 and 1988. It is undeniable that regulatory policy contributed to this wide fluctuation. Price controls stimulated demand in the early 70's, but caused the price of natural gas to exceed market clearing levels, thereby driving down demand, in the early 1980's.

Contrast this performance with what happened in other regions of the world. Natural gas production increased in both Canada and Mexico between 1973 and 1988. In the Soviet Union, gas production increased more than 300%; and in the Far East, it increased over 600%. With our dependence on imported oil increasing at an alarming rate, and given the relatively clean-burning qualities of natural gas, we need to ask ourselves why everyone else is producing and using more natural gas while we are not.

A second indication that regulatory distortions may persist is the existence of significant differentials between producer gas prices in different regions of the country. These differentials are not easily explained by a difference in transportation costs. For example, looking at spot prices, producers in the Rocky

Mountain and Mid-Continent regions are receiving consistently and significantly less for their gas than are producers in the Gulf Coast area.

Regional Spot Gas Price Differentials
($ per MMBtu)

			Average Differential vs. Gulf Coast	
		Gulf Coast Benchmark	Mid-Continent	Rocky Mountain
1988	Q1	1.83	-0.09	-0.20
	Q2	1.39	-0.09	-0.17
	Q3	1.60	-0.23	-0.37
	Q4	1.94	-0.28	-0.49
1989	Q1	1.71	-0.19	-0.35
	Q2	1.61	-0.24	-0.43

Source: Cambridge Energy Research Associates

In the third and fourth quarters of 1988, gas prices were lower in the Rocky Mountain region by 37 and 49 cents respectively than in the Gulf Coast. In the Mid-Continent region, prices were 23 and 28 cents lower than in the Gulf Coast region in this same time period.

We are exploring why these unusually[3] large differentials in the price of a fungible commodity exist. Regulatory barriers, exercise of monopsony or monopoly power and capacity constraints may be involved.

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[3] Price differences of 23 to 30% between Gulf Coast and Rocky Mountain natural gas markets are significantly greater than differences in the price of other commodities in regional markets. For example, the largest regional differential for #2 fuel oil is between the Salt Lake City and Houston market and was recently only 11%. The largest differential for unleaded gasoline was recently 17% between Minneapolis-St. Paul and Houston.

Third, it has been estimated that there are about 5.2 billion cubic feet (bcf) of U.S. natural gas shut-in [4], while Canadian gas imports are at record levels. This may be due to the proximity of Canadian gas to U.S. markets or to lower prices for Canadian gas, but we need to be sure that this situation is not caused by regulatory distortions that disadvantage domestic producers.

In the National Energy Strategy hearing that we held in Tulsa, Oklahoma, on August 8, 1989, a distinguished panel made up of Governor Clements of Texas, and Senators Boren and Nickles of Oklahoma, discussed at length the potential for natural gas to make a larger contribution to satisfaction of our national energy needs. However, they also noted problems with the current gas industry, particularly focussing on the apparent distortions in the Oklahoma (Mid-Continent) market.

We have made the major changes necessary to accomplish the first generation of natural gas regulatory and statutory reform. From this evidence of continuing market distortions, DOE draws the conclusion that we must now develop a second generation of natural gas statutory and regulatory reform. We believe further reform should focus on three areas: making new capacity available, providing proper rate incentives, and eliminating unnecessary regulation of pipeline gas costs.

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[4] Cambridge Energy Research Associates.

1. New capacity

First, there is a glaring regulatory problem in building timely new pipeline capacity to provide expanded, more competitive and more efficient service.

Currently, pipelines must obtain certificates of public convenience and necessity from FERC before serving new customers or building additional pipeline capacity. These certification requirements, imposed by the Natural Gas Act of 1938, act as barriers to entry into natural gas markets and delay the building of additional capacity to meet new demand.

In the fifty years since passage of the Natural Gas Act, the regulatory requirements imposed upon pipelines in order to get these certificates have grown complex, costly and time-consuming. Certification proceedings have practically evolved into a business unto themselves. Some certificate proceedings, even for relatively small interconnecting lines, last longer than the tenure of many Executive branch officials...or some Congressmen.

For example, take a look at the Northeast proceeding. Originally, 70 applications were filed. FERC organized these applications into 31 different projects. Over 75 parties attended a technical and environmental conference held in June 1988. FERC estimated that it would take 4 1/2 years to review the 31 projects proposed to bring natural gas to Northeast markets. This schedule prompted members in the House to organize a "Northeast Gas Markets Congressional Caucus" to help speed up the process of approving new pipeline capacity to the Northeast.

The pipeline industry is not the infant industry that existed in 1938, but a mature multi-billion dollar transportation business. To be competitive, the gas pipeline industry must be able to respond efficiently and decisively; pipeline capacity must be available to serve new customers and connect to new reserves. Unfortunately, as it stands currently, the regulatory process is a barrier to the gas industry's ability to respond in a competitive manner.

The enhanced oil recovery (EOR) market in California and the market in the Northeastern United States are examples of potential growth markets for natural gas. The gas industry wants to compete in these markets. California consumers want to rely on clean natural gas for generating electricity year-round, instead of just that part of the year when deliveries are not curtailed. New pipeline capacity to New England is essential if the Northeast is to meet its burgeoning power needs and reduce its heavy reliance on imported oil. Despite years of costly FERC proceedings, however, the construction of new capacity to serve either area is still some time away.

Certification proceedings involving the EOR market have been ongoing since 1985. The issue of additional pipeline capacity to the Northeast can be traced back to the FERC Boundary proceeding that originated in 1980. By July 1987, FERC determined that the Boundary proceeding had become an "unwieldy vehicle" for further consideration of proposals to serve the Northeast. The FERC terminated the proceeding and invited new pipeline projects to serve natural gas markets in the Northeast. The goal of this "open season" was to achieve service to the Northeast by late 1990 or 1991. In order to meet this deadline, FERC has and will have to continue to engage in extraordinary efforts.

While these two projects are the most often cited examples of the difficulty in getting new gas pipeline capacity built, it is not only the big projects that have problems. Even relatively small segments, the construction of which could eliminate bottlenecks and make the pipeline system more efficient and more flexible, encounter problems.

A recent example illustrates the point. A pipeline company requested certificates to build two segments of pipeline, totaling about 190 miles, and a compressor station. FERC eventually found that this additional pipeline would alleviate capacity constraints, allow greater utilization of storage capacity, increase reliability of service and integrate two of the pipeline's mainlines.

Much to FERC's credit they issued a certificate 13 months after the application was filed. To do so, however, FERC went to great lengths to deny requests for an evidentiary hearing by four other interstate pipelines who believed the additional pipeline was unnecessary. No customers of the pipeline proposing the capacity expansion complained.

This example illustrates a key problem: FERC's traditional certificate regulation is being used frequently by firms already in the market against those who want to enter that market. Firms seeking to avoid competition use the certification procedures to suppress competition by making costly and time-consuming interventions in certificate proceedings. These interventions cost their would-be competitors money, delay the proceedings, and do not benefit consumers or the public interest. That is why FERC has been urged by the Federal Trade Commission to discount the objections of a would-be competitor to a proposed new project.

The FERC has attempted to reform certificate regulation. In 1985 and 1987, as part of FERC's movement toward a more competitive natural gas market, FERC issued Order Nos. 436 and 500, which established voluntary programs for open access service by pipelines at flexible, non-discriminatory rates. One portion of these Orders, the Optional Expedited Certificate or OEC section, specifically dealt with the certification process by establishing an OEC procedure that provided for expedited treatment of applications for new service under the Natural Gas Act. For the most part, however, this OEC process has not proven to be expedited. It is currently being reviewed by a task force under the direction of Commissioner Moler.

Surveying all of this, we believe it is time for us to reexamine the regulatory process required for gas pipeline construction. Fortunately, there is a real world analogy that might be useful in structuring a reformed approach: the construction of oil pipelines. The physical construction process is analogous. However, because of statutory differences, oil pipelines do not need certificates to build new pipelines. Yet, these pipelines have been built in an environmentally responsible manner, and more quickly, to better serve producers and consumers.

We recognize that removing barriers to entry in the natural gas industry is no simple undertaking. Many affected parties, including the States involved, have concerns about how certificate reform will affect them. We must ensure that the environment is protected in any new pipeline project, but surely we can do better than the lengthy and cumbersome proceedings now required. What I suggest today is that it is time for us to work together on creative solutions so that pipeline certification is not a barrier to a flexible and efficient natural gas transmission network. A full range of solutions should be discussed, from complete elimination of the requirement of certification to eliminating or streamlining required standards and procedures and shifting the burden of proof to those who oppose the grant of a certificate.

2. Rate Design

Getting new capacity when and where it is needed is only half the battle. We need pipeline rate design that encourages the most efficient utilization of existing facilities. Many pipelines have capacity constraints in the winter months when demand is at its peak. In many cases, the development of additional storage could allow peak needs to be met without building more costly pipeline capacity. This new storage will not be built and used, however, unless there are economic incentives to do so. People who use the system at the "off-peak" time should get cheaper rates. This would encourage year-round use of the pipeline system and might actually lower winter peaks. By the same token, those who use pipeline capacity at peak times should pay higher rates than those charged in off-peak periods.

Increased efficiency in using our gas pipelines can also be achieved by properly structured firm and interruptible rates. Consumers who desire a day-in, day-out commitment of capacity should pay the full cost of keeping that capacity "locked-up." Consumers who do not wish to pay the price for such "firm" capacity rights should be able to pay a lesser fee for "interruptible" service. Transportation rates which are designed for interruptible service should not be "tilted" to subsidize those who receive firm, noninterruptible service. The service purchased at this lesser rate should, however, be truly interruptible. Otherwise interruptible customers may be paying less that the cost of the service they actually receive. Apart from being inequitable, this sends the wrong signals about what capacity is actually needed, and where.

FERC is moving to correct these rate design problems. I raise the issues here to demonstrate their importance in achieving a more flexible, responsive natural gas industry.

3. Deregulation of Natural Gas Prices

Order 451 Decision

The passage of the Wellhead Decontrol Act of 1989 signalled an impending end to 35 years of counterproductive regulation. Unfortunately, this regulation is dying not with a whimper but with a bang.

On September 15, the U.S. Court of Appeals for the Fifth Circuit reversed FERC's Order 451. This FERC Order implemented a rule proposed by DOE in November 1985 to raise the ceiling prices on old gas to a level more closely resembling market prices.

DOE proposed that FERC exercise its authority under sections 104(b), 106(c), and 109(b) of the Natural Gas Policy Act of 1978 (NGPA) to raise old gas ceiling prices to a new ceiling price that is "just and reasonable within the meaning of the Natural Gas Act." DOE proposed that the ceiling be raised to the highest ceiling price allowed for old interstate gas. (At the time there were over 15 categories of old interstate gas, with price ceilings ranging from $.31 to $2.50 per thousand cubic feet (mcf) in August 1985.)

DOE also proposed that the producer could only get the new ceiling price if the pipeline agreed to pay the higher price. (Pipelines were not required to give the producer the higher ceiling price.)

Lastly, DOE proposed that if the pipeline did not buy the gas at the new ceiling price, the producer would receive automatic abandonment and authorization to sell to another buyer.

In June 1986, FERC issued a final rule basically adopting the DOE's proposal. The two major changes from DOE's proposal related to multivintaged contracts and requiring a pipeline that did not want to buy the producer's repriced old gas to provide transportation to another buyer. Absent this latter provision a pipeline could refuse to renegotiate the price of the old gas and the producer might have no other market for his gas.

The Fifth Circuit completely reversed the FERC Order. The Court stated:

1. The new pricing structure for old gas exceeded FERC's statutory authority.
2. Pregranted abandonment violated FERC's responsibilities under the Natural Gas Act of 1938.
3. FERC did not deal adequately with the take-or-pay problem.
4. The mandatory transportation provision imposed a common carrier obligation that exceeded FERC's authority.

DOE strongly supports Order 451 and disagrees with the Court's decision.

This decision is troublesome for several reasons. First, it may prevent FERC from considering needed reforms, not only in producer regulation but in the regulation of oil and gas pipelines, and electric utilities. Second, if the decision results in severe financial losses to producers, it could have an adverse impact on drilling investments and natural gas deliverability. Lastly, it may necessitate lengthy and complicated proceedings at FERC. If far-reaching orders are totally reversed three years after full implementation, industry will find it impossible to respond to necessary regulatory-induced changes.

Thousands of contracts have been renegotiated as a result of Order 451. As a result of those renegotiations, producers have been given the opportunity to sell gas to buyers other than the pipeline, mostly to industrial customers and local distribution companies.

I will personally recommend that the Justice Department seek further judicial review of this Court decision if the Fifth Circuit does not modify its order.

Pipeline Gas Charges

In addition to rectifying this Court decision, there is further action that will free natural gas to move to market. Current policy creates barriers preventing the largest and most experienced buyer of gas, natural gas pipelines, from participating effectively in the gas market.

Pipelines are forced to charge customers not the market price for gas, but a price based on complex accounting and contractual arrangements that may have been made decades earlier. It is time to question whether continued Federal regulation of gas prices in this manner is appropriate.

What purpose does such regulation serve in an environment of wellhead price decontrol where competitive nondiscriminatory transportation is available? If the customers of a pipeline have nondiscriminatory open access transportation available, they can buy at a market responsive price from literally thousands of different producers, brokers, marketers and pipelines. Only the pipeline is prevented by regulation from making a competitive profit on gas if it has made wise purchase decisions. As we become more confident that we have worked out the kinks in open access, we should closely examine whether consumer interests or anyone else's are being served by continued federal regulation of the prices charged by interstate pipelines for natural gas.

In addition to removing impediments, we also must allow natural gas markets to use mechanisms that provide useful services in other commodity markets.

INSTITUTIONAL STRUCTURES MUST MATURE

The institutional structure of the natural gas industry has changed dramatically in the last decade. When the Natural Gas Act of 1938 was enacted, pipelines almost always acted as merchants. That is, they resold gas they had purchased from producers.

But it is different now. Pipelines have become transporters as well as, if not more than, merchants. The logic and inevitability of this development may be more readily apparent if you ask whether it would make sense for the C & O Railroad to buy (and resell) all the coal it hauls.

This change has been nothing short of dramatic. In 1982 about 22% of the gas in pipelines was being transported for third parties. By 1987 this figure had climbed to over 67%.[5] As this has occurred, independent brokers and natural gas marketers have also appeared on the scene.

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[5] Energy Information Administration, Growth in Unbundled Natural Gas Transportation Services: 1982-1987, DOE/EIA-0525, Washington D.C. May 1989.

The natural gas industry must continue to develop an institutional structure commensurate with the fact that natural gas is a commodity sold in competition with oil, coal, and electricity. Two additional mechanisms, in particular, will require some further thought and institutional development.

The first is the development of a natural gas futures market. Many consumers of natural gas -- if left free to choose -- seem not to desire a formal "reservation" of future supply resources for many, many years. Like those who consume and deal in non-ferrous metals and cereal grains, commercial handlers of petroleum seem to be turning increasingly to flexible-price contracts, to spot markets, and to futures-market price discovery. [6]

It is not yet clear whether the current proposal to develop a futures market providing for delivery in Katy, Texas, will get off the ground. Some think that a provision for delivery in Henry, Louisiana, would better comport with commercial reality. Others go so far as to suggest that a futures market can be so structured that delivery of "physicals" would not be required in the process of settling contracts. The contracts used in this latter sort of futures market would be settled by dollar payments of price differentials accruing over the contract period.

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[6] In recent years the "Brent" spot market in London has flourished, and the New York Mercantile Exchange, nearly defunct in 1976, has grown to become New York's largest futures exchange. This occurred after it turned away from potatoes to take up sponsorship of fuel oil, gasoline, and crude oil futures contracts.

Still another option has recently surfaced. Continental Bank in Chicago is formulating plans to market a futures-like contract within the next few months. This involves an arrangement in which Continental will put together parties who are willing to pay for price stability with parties who are willing to bear the risk of fluctuating prices for the chance of profit.

A futures market would allow gas buyers and sellers to reduce their exposure to price volatility. This would act as an insurance policy allowing potential consumers to invest in gas burning technologies where price volatility would otherwise preclude such investment.

Here too, we think it unsound policy for the Department of Energy to pick winners prematurely -- or at all. But the Department is interested in these potential developments, because the body of learned opinion that respects these market developments is growing, as is the volume of activity in such markets.

The second institutional development of which we must take some account is the growing diversity of contractual arrangements for handling natural gas. Here the Department of Energy can speak somewhat more definitively. The industry must tolerate a diversity of contractual arrangements.

Some analysts fear that neither banks nor institutional investors will finance exploration and development unless the producer can show a long-term contract for purchase of the gas. Other analysts believe that so long as gas can be marketed in a competitive and relatively non-discriminatory way, prevailing spot prices (and futures market hedging) will give investors and producers the needed price information to make appropriate investments. I am not here to resolve this debate.

My conclusion -- a simpler one, but one that may be more fundamental to the formulation of public policy -- is that public policy should neither require parties to enter into long-term contracts, nor prohibit them from doing so. But those who choose one or the other must bear the consequences of their choice, as is true for any other commodity transaction. Given the opportunity, the industry appears to be developing contractual institutions that work. They respond to the needs of the industry. They allow natural gas as a commodity to compete for and maintain a position in the national energy market.

RESEARCH AND DEVELOPMENT

The last barrier to a more effective natural gas industry is a technological barrier. We need to support R&D in technologies that can make a difference in the future.

We need to continue the on-going research into the geology of the natural gas resource base. We need to support the development of both better recovery methods for conventional resources in heterogeneous reservoirs as well as research into unconventional natural gas.

DOE and the industry also can support research efforts to find new applications for natural gas, and to achieve more efficient end-use of natural gas.

Fuel cell technology being developed by the Department shows promise as a more powerful and efficient alternative to an internal-combustion engine. The fuel cell produces direct-current electricity through an electrochemical reaction using fuel such as natural gas from a tank, and oxygen from the air. This cell has the potential to provide energy for many different needs, including producing electricity more efficiently than current electricity generating plants. The first generation of fuel cell technology is beginning to be introduced into the marketplace, and the next generation is under development.

DOE is currently funding a project through the Clean Coal Technology program to demonstrate the application of gas reburn with sorbent injection in three different boiler configurations. Its goals are to demonstrate a 60% reduction in NOx emissions and a 50% reduction in SO2 emissions with this technology. This $30 million project is being funded jointly between DOE and industry.

It is these kinds of R&D efforts that we need to support with the goal of future gas application in the marketplace.

Mr. Chairman and members of this Committee, this gas industry of ours is a truly remarkable thing. It was given up for dead just a few years ago. It was written off by customers looking for cheap and reliable fuels. Today we see this industry from a new vantage point. We've learned, we've removed unnecessary barriers and the industry became vibrant again. We need to finish the job we have started. The benefits to both the gas industry and to society itself are worth the effort. If we are successful, I believe that natural gas can reach its full potential as one of the key components in meeting our national energy and environmental goals in the future.

This concludes my testimony.

Senator **Bingaman**. Thank you very much.

I have some questions and maybe some of the other members of the committee will have questions, also.

Before we begin questions, let me just see if either Senator Wirth or Senator Ford would like to make an opening statement. If they would.

STATEMENT OF HON. TIMOTHY E. WIRTH, U.S. SENATOR FROM COLORADO

Senator **Wirth**. Mr. Chairman, thank you very much.

Just a brief commendation to you for holding this hearing and for the very distinguished panel of witnesses we have before us.

As you know, I have been particularly concerned not only about the natural gas production as a domestic resource, but also about the extraordinary importance of natural gas as we enter into a decade and probably the next century of increasing environmental concerns.

The issues of global warming and all of the related resource issues make it very clear that energy policy and environmental policy are becoming one and the same, and the more clearly we understand what a sound energy policy is going to be, the more clearly we are going to set ourselves on the course of having an enlightened policy related to the future of the globe.

Secretary Moore, I know, is putting a lot of thought into this. We greatly appreciate your focus and emphasis on this. You and Secretary Watkins have been very forthcoming on that, Henson, and we thank you very much and look forward to working with you.

And I hope that coming out of this hearing, Mr. Chairman, we may well identify areas in which we ought to move to merge the two again more effectively and more rapidly.

Thank you very much, Mr. Chairman.

Senator **Bingaman**. Thank you very much.

Senator Ford.

STATEMENT OF HON. WENDELL H. FORD, U.S. SENATOR FROM KENTUCKY

Senator **Ford**. Mr. Chairman, first, let me join with Senator Wirth in thanking you for holding this hearing, and the distinguished panel that you have assembled to testify today.

I would also thank you for giving me the opportunity to join with you in our co-firing legislation and I look forward to that being helpful.

And secondly, let me say to Secretary Henson Moore that both publicly and privately he has worked very hard. And I want to compliment you on the effort that you have put forward, trying to make things come together and work.

They say the biggest problem is people; you know, the three Ps, people, press and paper. And if you get rid of all of those, you would have a pretty easy job. But we do create the problems, because sometimes we will not give. But I do compliment you on the work that you are doing and what you are endeavoring to do. And I want to continue to work with you, and thank you for your efforts.

Thank you, Mr. Chairman.

Senator BINGAMAN. Thank you.

Secretary Moore, let me ask first, you have described some of the DOE initiatives or the thrust in this so-called—I think you referred to it as the second generation of natural gas statutory and regulatory reform. Have you identified as yet which of the proposed reforms of those you described may be accomplished within the framework of FERC's statutory authority under the Natural Gas Act and the Natural Gas Policy Act, and which, on the other hand, needs some additional statutory changes?

Mr. MOORE. FERC has been moving very aggressively, Mr. Chairman, in all of these areas, and we compliment them. They have not had much policy guidance from the Department of Energy in what they have done. We intend to rectify that situation and be far more active in letting them know what we think is the proper policy to be followed.

We believe that in all probability, to solve the three problem areas I have identified there is going to be a need for legislation to fully solve the problem. I am not sure FERC really has the authority to solve all aspects of all three problem areas.

Senator BINGAMAN. Let me also ask, DOE has authority under the DOE Organization Act to propose FERC rule-makings to implement this type of reform. Would it be your thought to do that, to actually use that authority to propose some FERC rule-makings, in order to carry this out?

Mr. MOORE. Yes. And I hope we have better luck than we did with Order 451. We started that one, and unfortunately, it has gotten the FERC in trouble. They made the right decision; we think the court did not, and we hope to see that decision reversed.

To answer your question, yes, we believe the Department of Energy needs to be aggressive. It needs to use the powers Congress gave it to initiate these proceedings with FERC. We will certainly do that.

To the extent that it looks like legislation will be required we hope to be able, by January of 1991 when we finish the National Energy Strategy, to suggest appropriate legislation to the Congress.

Senator BINGAMAN. Okay. We will look forward to getting your suggestions on that and trying to be helpful.

Let me make reference also, and just ask your view on this co-firing legislation that Senator Ford mentioned, that he and I are planning to introduce later this week, to promote the deployment of co-firing technologies. Do you have a view that you could state for the Department of Energy as to the role that co-firing can play as part of our overall energy strategy? Is that something that you have gotten into at this stage in your review of the possible energy policy for the country?

Mr. MOORE. Yes, Mr. Chairman. As you and Senator Ford probably know very well, the Department of Energy has been, for some time, through the Clean Coal Technology Program, experimenting with co-firing. We are finding, with some of the current technology we are using, that if you were, for example, to increase the amount of gas up to 10 percent in a co-firing, you would have a likewise approximately straight, linear 10 percent reduction in SO_2 emissions.

We also are beginning work in a more advanced form of co-firing technology called reburn technology, that we think will offer much better than a linear reduction in NO_x emissions. You will find a much cleaner burning of the coal by the use of natural gas in different stages of the burning process.

So, to answer your question, we definitely believe there is a real future for the co-firing of natural gas and coal with co-firing, we can use the Nation's coal resources, and use gas to make those resources burn efficiently and in a manner which addresses the environmental concerns of the country.

Senator BINGAMAN. Thank you very much.

Senator Ford, did you have some questions of the Secretary?

Senator FORD. One or two. I might say to the Secretary that it probably came as a cultural shock to all of you on the court's decision on 451. I suspect it is the first time in history that court has ever gone against the producers. So I understand how it might bother you.

Since I got that little lick in and everybody giggled a little bit, I always say if you lose your good humor in this job you might as well go home, I am glad to see you smile.

You have two projects in the Department of Energy going in co-firing. Could you give the committee a report? I do not expect you to elaborate on it now, but would you give the committee a report on those two projects and give us the prospects of the use of those?

I think it would be important to Senator Bingaman and I and those who are interested in the co-firing program to have an up-to-date progress report. So if you would do that for me, please, sir, I would appreciate it.

Mr. MOORE. Senator, we will certainly furnish it for the record.

We are working right now on an advanced project, where the goals are to use co-firing to reduce by 60 percent the amount of NO_x and by 20 percent the amount of SO_2, by means of reburning with natural gas. We are about to enter into a contract for another co-firing demonstration plant in Indiana, which we think will offer, through co-firing, a very effective way to reduce emissions.

The Congress has just provided funding in the appropriations bill for a reburn project in Ohio. We have a number of them underway, and we will, for the record of the committee, furnish an up-to-date analysis of all of the co-firing projects we have and what they have proven so far.

[The information follows:]

PROGRESS REPORT ON CO-FIRING PROJECTS

The following fact sheets provide current status of Fossil Energy's co-firing projects.

APPLICATION OF REBURNING TO CYCLONE BOILERS
NILES PROJECT

Program Objective:	To demonstrate ability of natural gas reburning technology to reduce NOx emissions from cyclone-fired boilers by at least 50%
Location:	Niles, Ohio
Boiler/Type:	125 MWe Niles Station Unit 1, Ohio Edison, cyclone-fired.
Sponsors:	Gas Research Institute (GRI), U.S. Environmental Protection Agency (EPA), Electric Power Research Institute (EPRI), Ohio Coal Development Office. Consolidated Natural Gas is providing significant service in kind as well as cost sharing a portion of the reburn fuel cost differential. Ohio Edison is providing significant service in kind, cost sharing a portion of the reburn fuel cost differential, as well as providing the demonstration site.
Prime Contractor:	Combustion Engineering, Inc., is the prime contractor and is also providing cost sharing to the program.
Subcontractors:	Energy Systems Associates (ESA) is responsible for data acquisition from all boiler testing. Physical Sciences Incorporated (PSI) is responsible for reburn economics and marketing evaluation. Mitsubishi Heavy Industries (MHI), the licensor of reburn technology to Combustion Engineering, will provide technical consultation.
Program Duration:	3 years; completion is scheduled for 4th quarter 1991.
Program Cost:	Currently estimated at $9.85 million.
Funds Available:	$7.6 million available or committed by sponsors.
Program Status:	Congress provided $2.5 million under the Interior and Related Agencies FY 1990 Appropriation for DOE participation in the Ohio Edison gas reburning project. Discussions are presently underway between DOE and CE for implementing the project.

FIELD EVALUATION OF COFIRING GAS FOR ENVIRONMENTAL AND OPERATIONAL BENEFITS IN WALL-FIRED PULVERIZED BOILERS

Program Objective: To design and conduct field experiments to document the technical and economic benefits of coring natural gas with coal for environment and operation improvements in wall-fired pulverized coal boilers. The four specific problem areas to be addressed are: 1) the "strategic" use of gas cofiring to trim short-term SO$_2$ emission peaks; 2) the use of gas cofiring to alleviate slagging problems; 3) the use of gas to maintain output during coal mill outages; 4) the use of gas to reduce the carbon content of fly ash collected in the particulate control equipment.

Location: Warrick County, Indiana

Boiler(s)/Type: Plant includes one 300 MWe and three 144 MWe wall-fired boilers. The 300 MWe boiler is jointly owned by the Aluminum Company of America (ALCOA) and Southern Indiana Gas and Electric Company (SIGECo.). The three small boilers are owned by ALCOA. The entire plant is operated by SIGECo. Under this program, the 300 MWe and one of the smaller boilers will be tested.

Sponsors: Gas Research Institute (GRI), Aluminum Company of America (ALCOA), Southern Indiana Gas and Electric Company (SIGECo), appropriate gas pipeline, and Radian Corporation.

Prime Contractor: Radian Corporation.

Subcontractors: Energy Technology Consultants, Inc., (ETCI) will play a major role in the development of conceptual engineering designs for gas coring and will coordinate test planning activities. Sargent and Lundy Engineers will have primary responsibility for developing detailed engineering designs and for overseeing the implementation of those designs in the field.

Program Duration: 18 months.

Program Cost: Total project cost $2 million to $4 million; GRI committed to $744,000.

Program Status: GRI contract with Radian is signed. Agreement between Radian and host site has been completed and site engineering is underway.

STATUS: 10/02/89

PROJECT: EER - Enhancing the use of Coals by Gas Reburning-Sorbent Injection

PROJECT DESCRIPTION: Project demonstrates gas reburning for NOx control along with sorbent injection for SO2 control (GR/SI) on two different boiler configurations (cyclone and tangentially fired). A third configuration (wall-fired) is covered under project scope but available funding presently limits it to two boiler types.

PARTICIPANTS:

Energy & Environmental Research Corp.	- Participant
Black & Veatch	- Subcontractor
Riley Stoker Corp.	- Subcontractor Boiler Analysis & Inspection
Illinois Power Co.	- Host Utility
Central Illinois Light Co.	- Host Utility
City Water, Light & Power	- Host Utility
Gas Research Institute	- Funding
Illinois Dept. of Natural Resources	- Funding

PROJECT COST/SCHEDULE:	SCHEDULE	$ DOE SHARE
PHASE I	06/78 - 07/89	$ 2,354,500
PHASE II	08/89 - 05/91	$ 8,416,506
PHASE III	05/91 - 12/92	$ 4,227,147
		$14,998,153 (50%)
	PARTICIPANT SHARE:	$14,998,153
	TOTAL PROJECT COST:	$29,996,306

DATE SELECTED: July 1986
DATE AWARDED: July 14, 1987

STATUS:

- On May 23, 1989, the Assistant Secretary of Fossil Energy placed the wall-fired boiler (Central Illinois Light Company's Edwards Station) effort on hold due to cost growth.

- Additionally, a Phase I & II overlap was authorized to allow long lead construction activities to commence at the Hennepin site.

- On July 28, 1989, Phase II of the project was authorized for the Hennepin and Lakeside projects subject to signature of the host site agreements and completion of the NEPA process.

Senator **Ford**. I appreciate that, Mr. Secretary.

And you know I went through the Depression and I understand fried mush and weak tea and that sort of thing, and my children and grandchildren have not, and I do not want them to ever experience that, but I experienced an energy shortage. As governor, I would drive in an 18-wheeler trying to take care of prisons and schools and industry in my state.

We had an emergency clause on natural gas, where a company could buy it and it would have to be transported under an emergency situation. And we were able to keep 20,000 people in one industry at work.

I watched Ohio go down the drain almost in the period of time when they could not get natural gas. And so I have been through it. And that makes me somewhat more, maybe, hesitant to watch it very closely, to see where we have got all kinds of natural gas, you talk about 123 trillion cubic feet in Alaska, that was in your statement, I think. Well, the transportation charge, when the price gets right, if the price gets right, it has to be $18 or something, you know, before you can transport that down and build the line.

So I want to be very careful that we do not start beating the drum of natural gas and move it out front, and we look over our shoulder and there may be some shortage.

And I am very concerned that we begin to put all facets of the energy field together so that we do not allow any one to carry more than its fair share for our safe energy future.

And I do not want to get into this moral equivalent of war again, as it relates to energy; I want to move forward in a manner in which we can all share natural resources.

I say that, being one that wants to work with natural gas and wants to use it, but as you know, there are no boilers being built now that are coal-fired, not a one. And I have an interest in coal. But that does say that there is something that we need to do to look at all the resources we have available, and this co-firing, I think, could be very useful.

And I do not want the western people to think they can get off without reclaiming the $3.20-a-ton coal coming out of the ground and they do not have any problems. They do have some toxic problems if you burn a lot of it.

So let us look at the whole thing and try to be fair and cooperative, which I find you very much that way, Mr. Secretary. So I put that out just to be sure that everybody understands where I am coming from.

Mr. **Moore**. Senator, the message is received. We agree with you totally.

Senator **Ford**. I am just telling you my fears. You know, you may not have it, and well and good.

Mr. **Moore**. No, we feel very strongly that the Nation's energy needs are not going to be solved by one resource, gas or oil or coal or nuclear or renewable or conservation. It is going to be solved by all of them, and trying to use all of them to the best of our ability.

Various parts of the country are going to choose one over the other because of economics or because of other reasons. Our job at the Department of Energy, is to perfect all of them and to have all of them available in the marketplace from which consumers can choose.

Coal plays a large part in that picture. We have, by no means, made the decision that natural gas is the only energy source.

The thrust of our testimony today is that it is a vastly improved source of energy, thanks to the actions of the Congress in the last several years and the actions of FERC. With a little more effort, it can reach an even greater potential than it is today.

We would be the last ones to say that everybody in the country should convert everything they are using to natural gas. That is not the idea of the testimony at all.

Senator FORD. Thank you, Mr. Chairman.

Senator BINGAMAN. Thank you, Senator Ford.

Senator Nickles, did you have both an opening statement and some questions for the Secretary?

STATEMENT OF HON. DON NICKLES, U.S. SENATOR FROM OKLAHOMA

Senator NICKLES. Mr. Chairman, I have an opening statement and I will just insert it in the record. I apologize for missing Secretary Henson Moore's opening comments, but I do welcome him before the committee.

Also, Mr. Secretary, I want to thank you for your appearance at regional hearings across the country, and particularly in Oklahoma. I think your comments were well made. And I also appreciate your patience and willingness to attend a long day of hearings and statements by myself and Senator Boren and others concerning some of the things that we felt were important for revitalizing and stabilizing the domestic oil and gas industry.

I know you did that not only in Oklahoma, but other places around the country. I know your time is a limited resource as well, and I am just most grateful of your indulgence and leadership in making that happen. I hope that we will see some good results.

[The prepared statement of Senator Nickles follows:]

STATEMENT OF SENATOR DON NICKLES

OVERSIGHT HEARING ON NATURAL GAS SUPPLY AND DELIVERABILITY SUBCOMMITTEE ON MINERAL RESOURCES DEVELOPMENT AND PRODUCTION

September 26, 1989

Mr. Chairman, thank you for holding this hearing to receive testimony on the potential for domestic natural gas to meet the anticipated new demands for this premium fuel.

The State of Oklahoma is the Nation's third largest natural gas producing state, and ranked second in 1988 for the number of gas wells drilled. Yet there are many of Oklahoma's gas wells that are shut in because of a lack of transportation to move the gas to market. There are new wells in eastern and southern Oklahoma that are waiting for pipeline connections. Other wells are shut in or restricted due to capacity bottlenecks on several major interstate pipelines that move the gas to out-of-state markets.

Oklahoma producers are ready and able to produce additional natural gas to meet our growing need for natural gas as an electric utility feedstock and alternative motor fuel. The Congress has finally passed legislation which sets up a firm schedule for the final elimination of natural gas wellhead price controls. This action and the virtual repeal of the Powerplant and Industrial Fuel Use Act last Congress pave the way for the free market to determine prices and uses of natural gas.

I look forward to the testimony of the witnesses on what remains to be done to further reduce regulatory impediments to the efficient supplying of natural gas by domestic producers to consumers.

Senator **Nickles**. I might ask you, as a first question, I implored you and the department to move as quickly as possible and not take a half a year or longer to put together the assessment of what needs to be done. Is that possible? Are you going to be able to move forward more quickly with the recommendations as a result of the field hearings?

Mr. **Moore**. We listened very carefully to you and Senator Boren and Governor Clements. All three of you made that comment. Certainly you forcefully did: Why is it going to take so long? And why cannot bright people sit down and figure out the right strategy without going through all this?

And I think the answer is probably you can. But the trick is we have got to be able to come forward with a convincing document that has a consensus, backed up by a database and computer model that can solve the questions of those people who may have a different viewpoint.

And we do not think we can do that in the time you suggest.

As a matter of fact, we are going to really be pushing it to have a report on the President's desk by our target date of December 1990. We hope to have some kind of report to this committee next April. That is what we said when we came through here for our confirmation hearings. We are still going to try to do that in April of 1990.

We are finding that the building of the computer modeling capability, alone, is going to take almost that much time, according to the National Academy of Sciences. We want to have the finest ability in the United States so that when you call us into a hearing we are giving your staff the very best data support they can get anywhere in the country.

Secondly, on the data gathering, we are working now, using a suggestion of the chairman, as a matter of fact, to bring the National laboratories into this. We have done that. We have assigned those laboratories into working groups of four and five on a particular subject matter. They will be reporting back by the middle of October, to try to begin to quantify such things as conservation.

How much can we get from conservation? Can we measure it? How much in each year and at what cost? And that is taking some time trying to quantify that.

And so we want to do it right, rather than do it hurriedly. As much as we would like to have this thing finished next month, by the end of the year, or by next April, when we have an anniversary date of delivering a report to the Congress by statute, I am afraid, to do it right, we are still looking at a time line. We are being bound, not so much on opinions we can draw or on the results of hearings, but more on the basis of the data gathering and the building of a computer model to help us assimilate what all the data mean.

I think that is going to be the hold up more than anything else.

We intend to use the time, however. We are going to have one more hearing of the type we had around the country in the northeast, probably in October. Then we are looking, at this point, at having additional hearings before the end of the year on targeted points, in order to be able to narrow this thing down. And then probably further hearings in 1990.

So you are probably looking at two more rounds of hearings. By the time we come to you with a game plan, while it may have been laborious and, in your opinion, it may have taken too long, we hope to bring you something which has a consensus behind it and which has a heavily documented database to help substantiate those conclusions.

Senator NICKELS. Mr. Secretary, let me urge you to move as expeditiously as possible and, two, to move forward with what you know will be some elements of that plan.

George Bush campaigned on doing some things to enhance the domestic oil and gas industry, and I think it is incumbent to move quickly.

If you wait until April to come to Congress, in all likelihood it will be difficult for us to make some of the tax changes that are necessary, like taking intangible drilling costs off as a preference item for the computation of the alternate minimum tax and a few of these other things.

You really need to be moving forward rather rapidly now if we are going to make those changes in this Congress. And so, I would just hate to see us not do anything legislatively or administratively or in your proposals tax-wise or other policy-wise than to wait until April for Congress and then maybe until December for the President to sign off on the report. That is going to be too late.

We have many in the energy industry, and I know that you are well aware of it, but they are already struggling to survive. Some are and some are not.

There are some things that we could do domestically either tax-wise or other considerations that we really need to be moving forward quickly on.

I do not find presidential sign off on policy of December of 1990—that is 13 months from now—as being as acceptable. The problem is too serious, it is too severe. Not only that, but the time lag you mentioned, having the right data coming into the model.

You might remember last December we were importing oil at $13.35. Things change, and they change rather rapidly in this whole system.

Secretary Herrington came out with a very extensive report, but a lot of that data, in my opinion, was faulty because it was obsolete. He was not up to date on the amount of oil that we were importing. At that time imports and the dependency on imports was much greater than even the worst-case scenario that was projected by the report.

And so, I am not interested—at least this Senator is not interested—and maybe others are—in a voluminous, detailed energy—here-is-our-energy-strategy-for-the-nineties report that no one will read.

I am interested in implementing policy that will help decrease the dependence on unreliable sources in the future and to move aggressively.

I noticed in your statement you mentioned some further moves towards, I guess, a second phase of statutory and regulatory reform, including making new capacity available and providing proper rate incentives.

Are you talking about the pipelines on the proper rate incentives?

Mr. **Moore**. Yes. For the proper utilization of the pipelines and the rate structure for the use of those pipelines, we need to avoid the bottleneck of having to build pipelines and the bottleneck it takes to build one.

For instance, we are looking at the idea—and this is coming out of the National Energy Strategy—where we are picking up on this and beginning to think this through. We are here today at the request of the Chairman, and are not really ready to start making specific proposals yet.

We have got a long way to go to thoroughly study this thing. It is not that simple as the rest of the panelists will tell you. It simply is not that simple.

We are looking at what can be done in the winter, in the peak load of the pipeline, to lessen that load; and at a rate structure which can be used by the pipeline at an off-peak time so that you are getting more natural gas from the producers to the consumers than you can under the current rate structure.

And we are also looking at the problem of whether these should be a Federal rate structure for the pipelines themselves in buying gas. Perhaps it makes them noncompetitive at the present time.

We see three real problems there. One, the building of the pipelines, two, the rate structure; and three, the use of the pipelines and the price the pipelines pay for natural gas. These are areas we have identified. They could be part of the second generation of regulatory reform to make natural gas flow more assuredly and more predictably from the producers to the consumers.

Senator **Nickles**. Let me ask one final question. And, again, Mr. Chairman, I apologize for missing the opening statement.

I notice that you have two or three pages in your statement concerning Order 451. I am going to read that with interest because I have interest, to say the least, in that decision.

Are you planning on appealing the decision?

Mr. **Moore**. Yes.

Senator **Nickles**. In the event that you are not successful, do you think Congress—that we should work on a bill to make some changes in 451?

Mr. **Moore**. It may be a good idea. I think it would be very helpful to see what FERC's analysis will show as a result of this decision, if it is ultimately lost, and then make a decision on that basis. We do not have that information yet either.

Senator **Nickles**. Would you work with many of us in the Congress who have expressed an interest? I think Senator Ford and Senator Bingaman——

Senator **Ford**. I might say to my friend that that will be harder to do than decontrol.

Senator **Nickles**. It is a complicated issue. It is not an easy issue. I understand that as well. But, would you work with those of us that have expressed an interest in it? If you would think that a statutory change is required, would you be willing to work with us to see if we cannot make that a reality?

Mr. **Moore**. Certainly we will sit down. We have every hope it will be overturned, but if it is not, we will go from there.

Senator **Nickles**. Mr. Secretary, Thank you very much.

Mr. Chairman, thank you.

Senator **Bingaman**. Thank you. Let me just reiterate for the Senators who have come in since we had the testimony of Secretary Moore, we have a couple of other witnesses who are here to debate the issue of where we go in the future, Mr. Sawhill, John Sawhill, and Mr. Kenneth Lay, and then we have a panel after that.

But anyone who does have questions of the Secretary, we are glad to hear those.

Let me defer to Senator Wirth at this point.

Senator **Wirth**. Thank you, Mr. Chairman.

I had a question related to transportation and the Clean Air Act. I know you all were involved in working on the President's Clean Air Act, and I gather from that that one of the goals of the administration is to try to encourage the transportation sector to be using more alternative fuels. Is that not one of the goals that the administration has set?

Mr. **Moore**. Yes, one of the three major parts of the bill is an examination of the type of fuel for tomorrow's transportation with the idea of improving the environment, and with the idea, hopefully, of removing our reliance on imported oil, and looking towards the next generation of motor fuels.

The Congress, of course, has already passed legislation creating the Alternative Fuels Commission, which has begun its work in trying to look at those issues as well.

The President is actually proposing a particular test program to build a million vehicles a year beginning in 1997 to begin testing certain fuels in certain markets to determine their impact. So, that is a major part of this legislation.

Senator **Wirth**. I know one of the decisions that was made was to identify a certain number of vehicles that were going to be test vehicles, and that was the approach that the administration followed.

The alternative is to set standards, say, for some kind of performance standards or pollution standards and let those in turn drive the market.

It seems to me that was obviously a choice that was made. Were you all involved in the decision that was made to go for a certain number of vehicles in some way rather than setting standards and then letting the market develop against those standards?

Mr. **Moore**. That was a very long and complicated process, Senator. I am not exactly sure about how, or who was where, in all of that process.

The ultimate decision the President's. As OMB Director Darman says, at some point you are either going to have a passenger vehicle built to carry one passenger and which has six fuel tanks or you are going to make the decision as to which of these alternative fuels is going to be the one we are going to test around the country.

And so, the proposed legislation takes the approach, and simply says that, at some point the Administrator of EPA is going to make a decision as to which of these alternative fuels is the one that really ought to be tested; and the signal to be given to the auto manufacturers and to the fuel manufacturers is that is the one we test.

It is meant to be an open competition between any number of fuels—gasoline or improved gasoline, compressed natural gas, ethanol, methanol and others.

The Alternative Fuel Commission, if we do our work in time, will hopefully be able to give some guidance to the Administrator of EPA.

But, an awful lot of testing is going on now. There are a lot of these vehicles on the road right now. They have been assimilating that data and making that data available to EPA.

The Administrator, if this legislation passes, will enhance his ability to make a right decision. That is the approach the legislation takes. It could be done your way.

I think there was the feeling that it was not clear that a true alternative fuels program was going to develop in the time frame the President would like to see and that there would be a continued effort to make cars smaller or engines burn more efficiently, which ought to be done anyway, in some of the tailpipe emission standards. This legislation, I believe, gets at that problem.

Senator WIRTH. I am not sure I know which is the best way to do it. I just wanted to clarify it was not my way or somebody else's way where there were two different choices that were taken, and there has been, I know, some nervousness in various industries about who is going to get what piece of the pie or whatever, and you are familiar with that.

Mr. MOORE. All the time I was working on the legislation, the model we were working from which became the President's bill, was that same model. I was not part of the discussions or negotiations that offered some totally different kind of a way to get at it.

Senator WIRTH. Let me ask you a related question, if I might, Mr. Secretary. I think many people are convinced that we want to encourage natural gas, not to the exclusion of other fuels by any means or not to have a heavy preference, but we certainly want to be encouraging natural gas for all of the reasons that you and I discussed earlier.

Are there steps that we ought to be taking, that the executive branch ought to be taking, or that we ought to be taking in the Congress that will encourage the broader exploration and production of natural gas?

Mr. MOORE. The President sent to the Congress a tax package he thought would encourage the greater production of both oil and natural gas in this country.

The Ways and Means Committee did not adopt that in its bill that will be on the floor, we guess, this week.

Hopefully, the Senate Finance Committee may take a look at that. It is something the President has suggested, has offered to the Congress, and it has not been adopted. It is something that ought to be looked at by the Congress.

The Congress has done the other part of the package this year, the decontrol of natural gas. It did do that. It did it in a bipartisan fashion and very quickly. It needs to complimented for that.

In years past, it removed the last vestiges of the Fuel Use Act, and so it did its homework there.

What I think needs to be done now, besides the tax incentives for production, is to look at the areas we are suggesting. We will know more about them as we finish our National Energy Strategy: the pricing of natural gas through the pipelines, the effect of whether it ought to be regulated, and the building of the pipelines to ensure the public can have access to natural gas.

We do believe there are some barriers left. If you look at some of the things going on in this country, you will find gas in your neck of the woods is not selling for the same price that gas on the Gulf Coast is.

It is kind of hard to explain that, except that we still have some barriers left which need to be worked on.

And so, I would urge this committee to work with us, or on its own, to begin to investigate what further needs to be done to make natural gas flow from the wellhead to the burner tip in a more efficient and predictable way. And I think there are still some things that can be done.

As a result of the National Energy Strategy, we may have some additional ideas to bring forth to the Congress that we are not really very knowledgeable on at the present time. But, there is a tax package, and there are these additional barriers that are regulatory that need to be looked at.

Senator WIRTH. Thank you, Mr. Chairman.

Senator BINGAMAN. Senator Murkowski.

Senator MURKOWSKI. Thank you, Mr. Chairman.

Mr. Secretary, I noticed on page 3 of your testimony you made reference to the nation having a 35-year supply of gas at cost of about $3 per 1,000 cubic feet in 1987 dollars at the wellhead.

I assume that that excludes the 126 trillion cubic feet of Alaskan gas.

Mr. MOORE. Yes.

Senator MURKOWSKI. And then further one——

Senator BUMPERS. Senator, for my benefit would you repeat that statement.

Senator MURKOWSKI. Yes. On page 3 of the Secretary's testimony he indicated that the nation has a 35-year supply of gas at a cost less than $3 per 1,000 in 1987 dollars at the wellhead, and I asked the question of whether that volume included Alaska's reserves, and the answer was no.

Mr. MOORE. It does exclude it.

Senator BUMPERS. You are saying those reserves are in the Lower 48?

Mr. MOORE. Yes. And the reason for it, simply, is that the Alaskan reserves are not deliverable right now. There are no pipelines.

Senator MURKOWSKI. My second question, Mr. Secretary, is the further indication on that same page where you indicate that the recognition of 126 trillion cubic feet of gas to be available in Alaska, and you indicate when the market price of natural gas in the Lower 48 justifies construction of facilities required to bring that gas to market.

My question, as you might suspect, is at what price. In other words, what price would you have to have to bring that gas to market.

Mr. MOORE. Senator, we have not done calculations at the Department of Energy. We are told by people interested in building the pipelines that the delivery price of the gas alone would be $3 a

1,000 cubic feet for them to be able to build and finance the pipelines.

Senator MURKOWSKI. So, they could advertise the delivery system, but they would not make any money or the owners of the gas would not get any return?

Mr. MOORE. That is correct.

Senator MURKOWSKI. And that is distribution, of course, in domestic distribution scheme as opposed to an export scheme.

Mr. MOORE. Yes.

Senator MURKOWSKI. In your energy study which you are preparing, are you going to be able to refine those figures any further? It would seem that since it is such a significant reserve that we may be looking at as a matter of necessity in the future that you might want to indicate what kind of market price you would have to break to encourage the development of the project and a return to the investors.

Mr. MOORE. The answer, Senator, is yes, that is precisely the kind of database we are trying to build that we do not have now.

Senator MURKOWSKI. So, I would assume, then, those figures would be in your energy report.

Mr. MOORE. Yes. Better yet, they will be on a moving database that, given time, we can give you that estimate based upon changes in construction prices or whatever.

Senator MURKOWSKI. Okay. Well, we will just look for that in the report, and then I assume it would be premature to expect you to be able to submit it for the record, is that right, in this hearing?

Mr. MOORE. Yes.

Senator MURKOWSKI. My last question, Mr. Chairman, is how much control do we really have over our alternative energy sources as we recognize the phenomena that may be current or may be temporary or may be lasting?

Our increased dependence on crude oil, 50 percent or thereabouts currently from the Middle East—there are substantial reserves and a very low lift cost, which I understand is, in many cases, under $3 a barrel or thereabouts, and as long as they keep a price between—well, 17, 14, 17, 20, 22 dollars, somewhere in that range, it very much discourages the economics to support alternative energy resources.

And my friend from Colorado is very committed, as I am, to the realities that we have got to have energy, but is it something that the government is going to have to step in and consider the subsidy all over again in order to encourage these alternative sources, or are we indeed going to find it attractive enough for the private sector in the foreseeable future to come about with encouraging developments.

It seems to me that it is a bit beyond our control since they have the capability in the Mideast to simply keep this price structure in a range that the economics do not support alternative energy.

I wonder if I could have your views on whether your energy study is going to address that dilemma?

Mr. MOORE. Yes, Senator, it is. It has to try to quantify at what price these things will become feasible as we begin to see how much conservation we can get, how much renewable energy resources we can get, and, at what cost; so we can begin to make recommendations and this committee can begin to make decisions on how they should be adjusted.

The pattern that we see as a result of a National Energy Strategy versus what the Congress may want to see.

Senator **Murkowski**. Do you have a figure offhand that oil would have to go up to in your opinion to really cause us to take off on an alternative energy alternatives?

Mr. **Moore**. No, I do not, Senator. I think that you are correct that the OPEC countries know that figure better than we do, and they are keeping the prices of oil currently below that figure.

Senator **Murkowski**. Then I think you have answered my question. They are basically capable of holding us hostage to continue to be committed to their abundant resources because of the relatively inexpensive cost of that energy vis-a-vis the alternative of pursuing alternative energy resource capabilities, and that is a very dangerous position to be in.

Mr. **Moore**. That is, but that is not a static position. It is constantly moving.

I have toured our laboratories at DOE. We are making good progress. The cost of the technology of fuels from biomass, for instance, and electric solar generating facilities, are coming down as they continue to improve the technology.

Now, of course, if these became a major factor in the market, I suppose that OPEC could reduce its prices of oil. It could come down to meet that threat.

Well, that is the kind of thing we are going to have to work with in the future and what we have to bring to you is a strategy and a database that helps us make those decisions.

Senator **Murkowski**. Well, I would encourage you in that study to indicate how we can best maintain our energy self—energy security from the standpoint of being dependent upon what somebody else did, vis-a-vis being able to direct our own alternatives the way we feel we can best meet our energy needs from the standpoint would you rather be dictated to or dictate to.

And I think this country with its tremendous energy resources in coal and oil that still lie undeveloped, we have that capability if we want to have the fortitude to address it.

Thank you, Mr. Chairman.

Senator **Bingaman**. Thank you.

Senator Bumpers.

Senator **Bumpers**. Mr. Secretary, you state that we have a 35-year supply of natural gas based on last year's consumption of 18 trillion cubic feet. And you also state that that is a 10 percent increase in consumption over the preceding year.

If gas consumption continues to go up at the rate of 10 percent a year, how long is our gas supply?

Mr. **Moore**. Well, it will not last as long, obviously. We do make a projection of what the gas consumption will be in the year 2000. I am trying to figure out what page that is on. It goes up.

Senator **Bumpers**. I think that is on page 4, is it not?

Mr. **Moore**. So, at this point we do not have the ability, with the modeling capability and information we have, to go much beyond that in terms of consumption. There again, that is one of the things we are trying to build in the National Energy Strategy database.

We want to be able to answer this question for you, to be able to tell you in any one year what the energy mix is going to be, as we see the current market forces.

Now, the projection we have given you is about the best we can do at this point.

Senator **Bumpers**. Well, first of all, Mr. Secretary, I want to congratulate you on your testimony. You have at least put figures in here that we can use to reach our own conclusions, and they are not precise into the far future and so on, but at least you have given us something here because I remember, I think, the year I was elected governor, this country had 225 trillion cubic feet of proven reserves in natural gas, and consumption of natural gas was not that much lower than it is right now.

But today the national reserves have dropped from about 225 trillion cubic feet to 168 trillion cubic feet.

Now, you say there are 307 to 507 trillion cubic feet of undiscovered conventional natural gas and did I understand you to say to Senator Murkowski that that does not include the 160 plus trillion cubic feet in Alaska?

Senator **Murkowski**. 176.

Mr. **Moore**. Yes.

Senator **Bumpers**. That does not include that.

Mr. **Moore**. Yes, it does not.

Senator **Bumpers**. Did you not include that because you do not think it is ever going to be economically feasible to get that gas down here?

Mr. **Moore**. The report that we have issued, and which the U.S. Geological Survey has issued, have all of this broken out separately. The terminology or the tests you use to determine in what category you put this gas is the way you determine where it should go.

Basically what we are saying is the fact that for the test that is being used, these are the figures that we have.

If you loosen up the test, meaning beginning to use, on conventional sources of recovery, higher prices, then your reserves grow.

Senator **Bumpers**. We are talking about conventional natural gas now?

Mr. **Moore**. Correct.

Senator **Bumpers**. What are Canada's recoverable reserves right now, if you know?

Mr. **Moore**. The newest one would be the methane seam gas.

Senator **Bumpers**. I am not talking about the kind of gas. I am talking about their total reserves of natural gas, recoverable reserves comparable to the 168 trillion cubic feet in the United States. Do you know how much natural gas Canada has?

Mr. **Moore**. Let us see. We have got some figures here. Let me check right quick and see.

No, we do not have that figure here.

Senator **Murkowski**. I might point out to the Senator from Arkansas that the gas that was found in Alaska was not found as a consequence of an effort to find gas. It was accidental.

Senator **Bumpers**. I understand that.

Mr. **Moore**. We do not have that figure with us. We can certainly furnish it for you. We do have that.

[The information follows:]

ESTIMATED RESERVE ON CANADIAN NATURAL GAS

The estimated proved reserves (recoverable) of Canadian natural gas is 95.1 TCF. (Oil and Gas Journal, December 26, 1988).

Senator BUMPERS. I would like to know that.

You state in your testimony we are importing 7 percent of our natural gas from Canada.

Mr. MOORE. Yes.

Senator BUMPERS. Of course, I do not have any reason to believe they are going to be willing to fill the void as our reserves dwindle and our consumption either remains constant or goes up. I do not have any reason to believe the Canadians are going to be all that generous in shipping us an inordinate amount of their reserves.

How much did the Department of Energy ask for this year for research and development of enhanced recovery and/or development of unconventional natural gas?

Mr. MOORE. That is in the fiscal year 1990 budget before the Congress now.

Senator BUMPERS. Yes.

Mr. MOORE. $4 million in the area of gas, out of $24.5 million.

Senator BUMPERS. How much for natural gas?

Mr. MOORE. $4 million.

Senator BUMPERS. That is like saying we are not really serious, is it not?

Mr. MOORE. That is something we hope to see rectified in fiscal year 1991. That budget was largely done before we came here, and it is something that every year DOE asked for a certain amount and every year the Congress gives more.

And we understand that, and we hope to see fiscal year 1991 reflect what really is the thinking between DOE and Congress.

Senator BUMPERS. Mr. Secretary, I am looking at a figure here that——

Mr. MOORE. The Gas Research Institute does spend $174.9 million in addition to that, and we do fund some of their research. We do work with them on some of their research.

Senator BUMPERS. Well, Mr. Secretary, I want to say that I certainly share Senator Wirth's concerns about developing alternative fuels and unconventional natural gas on a crash basis because I think it will all happen sooner than anybody thinks, and I am not one—I recall all the charts and graphs and speeches that were made on the floor when we deregulated oil.

I did not vote for it. I do not know. I might have been wrong, but there is one thing I did not believe, the figures. They were talking about how much oil we were going to have if we just deregulate the price on a very simple proposition that God just made so much of it. I do not care how much the price is. You are not going to find it if it is not there and almost ever since that happened, the oil reserves have been declining in this country.

Production, as you know, is going down every year and has for the last five years. And so, I just do not want us to hang our hat on some kind of a theory that if gas just goes to $10 an mcf, we would find all we wanted. There is not any question that if gas were at $10 an mcf, alternative gases would become very popular.

But to suggest that they are going to go out and find it where it does not exist just because the price goes up is foolish in the extreme. And I am pleased to hear you say that next year those figures that you will recommend for R&D will be substantially greater. Thank you, Mr. Chairman.

Senator **Bingaman**. Thank you very much.

Mr. **Moore**. If I might just say in brief answer to Senator Bumpers, he has given some very thought-provoking comments. I guess at this point there would be no point in us entering into a debate on the pricing, price control of oil and natural gas. The Congress has spoken its wisdom on that.

We are not saying that the price alone is going to solve the problem. That was not the thrust of my testimony.

Senator **Bumpers**. I know it was not, and I applaud you for that.

Mr. **Moore**. What we are saying is that at a reasonable price we do have a reasonable amount of reserves. Is that the answer to the energy picture in the United States? No. It is a way to maximize that resource for as long as we have it.

I think a lot of people view these things as being at some point in the future, at some point in the 2000s, the middle 2000s, we hope our National Energy Strategy will help with that.

We have got to begin to think about other forms of fuels and the conservation of these fuels that we do have. We also want to make the point that we are trying to begin to use research, and we are developing ways to get the gas we do have more efficiently. Through the horizontal drilling programs and the better reservoir imaging through computer programs which DOE has done, they are putting these things out in the hands of small producers such as those which exist in southern Arkansas, east Texas, north Louisiana and elsewhere.

But the point is that we are not trying to in any way lead you to believe we are coming in here tell you that, if we had an astronomically high price, for this day and time, of natural gas all of the energy problems would be solved. They would not be.

Could you find more gas at $10, a 1,000 cubic feet? Sure. Will gas ever get to $10 1,000 cubic feet? That we do not know. We sure do not see it right now.

Senator **Bumpers**. Well, in all fairness, I will say—I mean, I just felt this way about the United States because, you know, we have been drilling holes here a long time. We found the technology that a lot of countries have not had, but the price of oil has led, in my opinion, to greatly increased international reserves of oil.

You and I both know, for example, that Iraq has tremendous reserves that they have just discovered in the last few years, and I do not know what the figure is, but I think the reserves of oil in the world are probably two to three times as great as they were when the oil embargo occurred in 1973, and I think the price is a factor.

Price is always a factor, but only to a point. Thank you, Mr. Chairman.

Senator **Bingaman**. Thank you very much.

Mr. Secretary, we appreciate all of your time and your willingness to be here today to answer our questions, and we look forward to following the progress you are making there at the Department of Energy.

Mr. MOORE. Thank you, Mr. Chairman.

Senator BINGAMAN. As I mentioned earlier, we will depart somewhat from the standard hearing format with the first panel of witnesses, John Sawhill is the Director of McKinsey & Company, a leading consulting firm. Mr. Sawhill served with great distinction as a federal energy official in the Ford and Carter administrations in the 1970s.

Ken Lay is the President and CEO of Enron Corporation, the largest natural gas pipeline company in the United States and one of the largest independent natural gas producers. Mr. Lay is also chairman of the board of the Interstate Natural Gas Association of America.

The format that we are going to follow during this panel is that Mr. Sawhill and Mr. Lay will make opening statements setting forth their positions on natural gas supply and deliverability and then each gentleman will have the opportunity to rebut the other's position.

Once they have concluded, those of us on the subcommittee will have an opportunity to ask some questions.

Mr. Sawhill, thank you very much for being here, and if you would just proceed.

STATEMENT OF JOHN C. SAWHILL, DIRECTOR, McKINSEY & COMPANY, INC.

Mr. SAWHILL. Thank you very much, Mr. Chairman. I appreciate the opportunity to be here.

I will briefly summarize my testimony, which I have made available to you. There are some exhibits attached to it, which I might call your attention to. The thrust of my testimony is that the end of the natural gas surplus is coming and that we have to prepare ourselves for that fact.

One of the points that I have tried to make in my testimony is the distinction between the natural gas region resource base in this country and the deliverability of natural gas reserves.

And I would like to just make a few comments to highlight that distinction.

I have tried to show in exhibit one of my testimony the decline in drilling activity that has taken place since the early 1980s. And as you can see, the decline since 1985 has been about 50 percent. And the drop off since 1981, I think, has been almost 70 percent.

So we have had a very rapid decline in drilling activity, not surprising given the gas surplus that we have experienced.

The second point that I would like to call your attention to is depicted in exhibit two of my testimony, which shows the production of natural gas relative to the yearly addition of natural gas reserves. And as you can see, the yearly addition of reserves have been very close to production.

But I believe that that figure is somewhat misleading. The proportion of gas reserve additions accounted for by revisions and extensions was growing very rapidly during the decade, while the contribution of discoveries in either new or old fields declined quite sharply.

In fact, revisions have increased from 2.5 percent of total reserve additions in the early 1980s to over 40 percent in the last three years. And that is particularly highlighted by the very large amount of revisions that occurred in the preliminary figures that we have seen for 1988.

The EIA recently announced that reserve additions in 1988 were 20.1 TCF. That is roughly 120 percent of 1988 production, and double the level of additions in 1987. But, as I have indicated, unfortunately, 48 percent of the reserve additions in 1988 came from an area, western New Mexico, where a change in ownership appears to have led to a one-time reassessment of reserves in the ground.

So that, even though we have had a nominal large increase in reserves, the concern that I have is that so much ot this reserve is accounted for by revisions that I do not think that that actually is affecting near-term deliverability.

Revisions were not the only category, however, of reserve additions to increase in the 1988 EIA estimates. New reserves from discoveries increased by 37 percent over 1987 levels. Nevertheless, discoveries in 1988 were down by almost 50 percent since 1981.

And the other concern I have, frankly, is that many of the recent discoveries have not been brought into producing status. For example, largely offsetting the 1.6 TCF of new discoveries in the Gulf of Mexico was a 1 TCF increase in non-producing reserves.

As I have tried to show in exhibit three of my testimony, there has been quite a large increase in the amount of non-producing reserves since the early 1980s. As a matter of fact, the change since 1983 has been about 10 TCF, or about 2 TCF per year of deliverability.

Once again, the announced reserve additions are encouraging, but when we examine the figures closer, we find that near-term deliverability still could be a problem. And that is the distinction that I am trying to draw here. That we have announced large changes in reserves, a lot of those changes are actually revisions, which do not impact near-term deliverability. And even the new discoveries often are in what we call a non-producing status, and also, do not impact deliverability.

So that the concern I have is that we are headed for a deliverability crisis because the drilling activity has declined so sharply, we just have not been adding the quality of reserves to support the kind of demand for natural gas that we have been adding.

My estimate is that near-term gas deliverability is declining about 6 to 8 percent a year, or about 1 TCF.

And if you were to look at exhibit four in my testimony, it shows deliverability declining to the point whereby, next winter, if we have any kind of cold weather, it appears to me that we are going to have a shortfall of supply, and many users of natural gas are going to have to switch off, gas to oil.

While deliverability declines by the 6 to 8 percent that I have mentioned, demand has been growing by about 4.5 percent in 1988 over 1987 levels. And the concern I have is that much of this new gas demand is inflexible. That is, the gas industry is adding residential and commercial customers and cogenerators that have limited ability or incentive to switch to alternative fuels.

So we have got rapidly declining deliverability, deteriorating quality of our gas reserve base, and a much more inflexible demand. And that is the concern I have about the near term.

Now, it seems to me that this tightening supply and growing demand can only result in higher prices. And nobody knows really how high prices will go. Our models indicate that prices will have to rise well above $3 per MCF in order to begin to bring supply and demand back into balance.

I have tried to indicate in exhibit five in my testimony—we have projected out to 1995, and with a sharp decline in deliverability, our so-called low case, we would have a shortfall of about 5 TCF of gas.

Now, there would be a supply response, some additional LNG would come into the country, some additional supplies would come from Canada. And the higher prices would bring on some new deliverability from newly discovered reserves in the United States. But I also believe that we would have to shed some of the marginal gas load.

For example, that portion of the gas load that is capable of burning high sulfur residual oil, I think, would disappear and switch to oil. And we might even have to dip down into the medium- or low-resid load in order to bring supply and demand back into balance.

As I say, nobody knows exactly how high prices will go. But we certainly feel that probably prices will rise to the point where natural gas will sell on a parity with crude oil at the wellhead. So that if oil were to be $25 per barrel in the early to mid-1990s, natural gas wellhead prices would be about $4 per MCF.

I have indicated in my testimony some of the implications that I think this has for national energy policy and regulatory policy at the federal and the state level. And I have also indicated that it seems to me important that government policy, in considering natural gas, take into account that we have to be careful about predicating policy on the belief that gas is available to meet increased demand at prices even remotely similar to what they are today.

That would conclude my testimony, Mr. Chairman.

[The prepared statement of Mr. Sawhill follows:]

NATURAL GAS SUPPLY AND DELIVERABILITY

Testimony of
John C. Sawhill
Director
McKinsey & Company, Inc.

U.S. SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
Subcommittee on Mineral Resources
Development and Production

Washington, D.C.
September 26, 1989

NATURAL GAS SUPPLY AND DELIVERABILITY

John C. Sawhill

The end of the natural gas surplus is coming, and gas consumers may be in for a shock. The amount of deliverable natural gas is falling rapidly. At the same time, gas demand - much of it inflexible - is increasing, and this will only worsen the supply shortfall.

I will elaborate on this troublesome supply and demand outlook and discuss several related policy issues.

PROSPECTS FOR THE NATURAL GAS INDUSTRY

The major problem in natural gas supply - sharply declining deliverability - is an inevitable consequence of the tremendous fall-off in gas drilling during the 1980s. As shown in Exhibit 1, drilling of wells containing natural gas (as measured by total feet drilled) declined by 70 percent since the early 1980s and by 50 percent since 1985. This drop-off is understandable; producers hardly had an incentive to look for gas during a period of low spot prices and a persistent "gas bubble." As shown on this first exhibit, the proportion of drilling that was exploratory - that is directed at finding new reserves as opposed to developing previous discoveries - declined even more rapidly.

Although drilling declined rapidly in the 1980s, reserve additions held up fairly well and came relatively close to replacing production. As shown in Exhibit 2, reserve additions in 1982 through 1987 replaced 80 percent of Lower-48 natural gas production. This level of reserve additions is misleading, however. As Exhibit 2 also shows, the proportion of gas reserve additions accounted for by revisions and extensions was growing during this decade, while the contribution of discoveries in either new or old fields declined sharply. In fact, revisions have increased from 2.5 percent of total additions in the early 1980s to 40 percent over the last 3 years.

Some of these so-called "paper additions" were motivated by financial considerations; others merely extend the life of a field and do not increase its short-term deliverability. We, therefore, tend to discount the large reserve revisions when estimating the deliverability of natural gas over the near term.

The EIA recently announced that reserve additions in 1988 were 20.1 tcf, roughly 120 percent of 1988 production and double the level of additions in 1987. Unfortunately, as is evident from Exhibit 2, almost half of these additions were made up of revisions, 48 percent of which came from one area - western New Mexico - where a change of ownership appears to have led to a one-time reassessment of reserves in the ground. This delayed recognition of reserves found a long time ago is unlikely to lead to a significant increase in near-term deliverability, although it does indicate that the western New Mexico area will be producing natural gas for quite some time into the future - good news for the long term, but not much help during the next few potentially cold winters.

Revisions were not the only category of reserve additions to increase in the 1988 EIA estimates. New reserves from discoveries increased by 37 percent over 1987 levels. Nevertheless, discoveries in 1988 were down by almost 50 percent from 1981, and many of the recent discoveries have not been brought into producing status. For example, largely offsetting the 1.6 tcf of new 1988 discoveries in the Gulf of Mexico was a 1.0 tcf increase in nonproducing reserves. As shown in Exhibit 3, at least 20 percent of current Lower-48 proved reserves are in nonproducing reservoirs, versus 13 percent 6 years ago. This equates to a loss of 10 tcf in reserves or about 2 to 2.5 tcf per year of deliverability. Once again, the announced reserve additions appear to be encouraging, but a closer examination reveals that the near-term deliverability problem remains.

McKinsey's basin-by-basin analysis of U.S. gas producing regions showed that this general decline in both the level and quality of reserve additions has had a significant impact on deliverability. In the Louisiana Offshore, we estimate that deliverability has declined by over 20 percent since 1981. Worse yet, where there is additional deliverability, there is often insufficient capacity in the pipeline system. Both the Hugoton and Rocky Mountain areas lack adequate pipeline capacity. Additionally, efforts to bring Canadian natural gas to New England through the Champlain pipeline appear to be undergoing difficult times as at least one large natural gas company has backed out of the project and the pipeline's owners speak of "downsizing" the project by nearly 40 percent. In general, there is a need to find ways to move gas from the Mid-Continent and Rocky Mountains areas where gas is in surplus to those areas supplied from short-lived reserves in the offshore Gulf of Mexico and Gulf Coast areas. Although projects to debottleneck and expand the pipeline system are underway, they are being impeded by regulatory processes and debates about the proper certification required. As a result, most major projects are unlikely to be completed before the early 1990s.

When we combine our estimates for all basins, we see near-term gas deliverability declining by 6 to 8 percent per year, or about 1 tcf per year. As shown in Exhibit 4, this decline is so steep that a shortfall of supply is inevitable in the next year or two regardless of the weather.

Meanwhile, demand continues to grow. In 1988, natural gas demand increased by 4 1/2 percent over 1987 levels. Much of this new gas demand is inflexible. The gas industry is adding residential and commercial customers and cogenerators that have limited ability or incentive to use oil or alternative fuels.

With tightening supply and growing demand, the end result can only be higher prices. Most producers now tell us that in order to bring forth substantial additions to reserves, prices would have to rise well above $3.00 per mcf. Our models tell the same story.

It is important to note that the drilling spurt of the early 1980s reflected the incentives created by new gas prices of as much as $7 per mcf. While some groups, such as the American Association of Petroleum Geologists, have stated that the United States has a reserve base of 500 to 600 tcf with prices at $3.00 per mcf, most of these reports have failed to address the issue of timing. While the United States might ultimately recover such volumes at those prices, the rate of development would be very slow. Hence, we take issue not with the estimates of such groups, per se, but with the implication that such a large base of yet-to-be discovered reserves precludes a near-term deliverability crisis.

Our estimate of the likely response to a shortfall in deliverability from current reserves is shown in Exhibit 5. Both supply and demand responses will be required. As markets tighten, prices will rise, forcing consumers who can readily use residual oil to switch off of natural gas. Higher prices will also result in a supply response - existing LNG plants will be utilized, imports from Canada will increase, and additional drilling in the Lower-48 will result in some increased deliverability. We estimate that prices necessary to bring forth the appropriate demand and supply response are in the range of parity with crude oil. If oil is about $25 per barrel in the early-to-mid 1990s, we estimate that natural gas wellhead prices would be about $4 per mcf.

IMPLICATIONS FOR NATIONAL ENERGY POLICY

Legislative and regulatory actions during recent years to remove restrictions from the gas market are to be applauded. This past summer's legislation to decontrol all natural gas at the wellhead is clearly in the public interest. Along with elimination of demand restraints in 1987 (the repeal of the Fuel Use Act), this legislation ends the industry's history of federal regulation of both the supply and demand side of the natural gas business. Regardless of the future supply and demand balance, the ability of prices to adjust quickly, providing incentives to producers and consumers to respond, will be our best assurance of reliable supplies at the lowest possible price.

While much federal regulatory change has been constructive, some additional steps are necessary at both the federal and state levels. Regulatory and market changes in the 1980s resulted in a dramatic and excessive shift away from longer-term supply arrangements and toward spot transactions. A new balance of accountabilities between buyers and sellers must be established, leading to a resurgence of longer-term supply arrangements and better prospects for future natural gas supply availability.

To this end, state regulatory policies, which have emphasized the price advantages of purchasing gas on the spot market, should become more sensitive to the advantages of long-term gas supplies. Regulatory policies should allow - indeed encourage - all parties to decide upon the proper mix of gas supplies for their needs. Those policies should not dictate strategies, such as "least-cost" requirements, that tend to mandate a particular approach. In addition, federal regulators should not try to "micromanage" industry participants. Rather, they should look favorably on arrangements negotiated between pipelines and their customers and between producers and pipelines in situations where these markets are workably competitive.

Natural gas is an environmentally benign fuel, and public policy should encourage its contribution to solving our nation's pressing environmental problems. To this end, customers should have flexibility in choosing how to meet pollution reduction standards in the most timely and economic manner for their individual circumstances. Policy flexibility should apply equally well to electric utilities choosing between installing pollution devices or co-firing with natural gas as to automobile owners choosing among less polluting alternatives (e.g., compressed natural gas, methanol, propane, electricity, or improved gasoline performance).

Government policy should not, on the other hand, be predicated on the belief that natural gas is available to meet increased demand at prices even remotely similar to today's wellhead prices. The best mechanism to meet environmental policy objectives is likely to be market incentives - such as those provided by a carbon tax that would stimulate new gas supplies - rather than regulatory prescriptions.

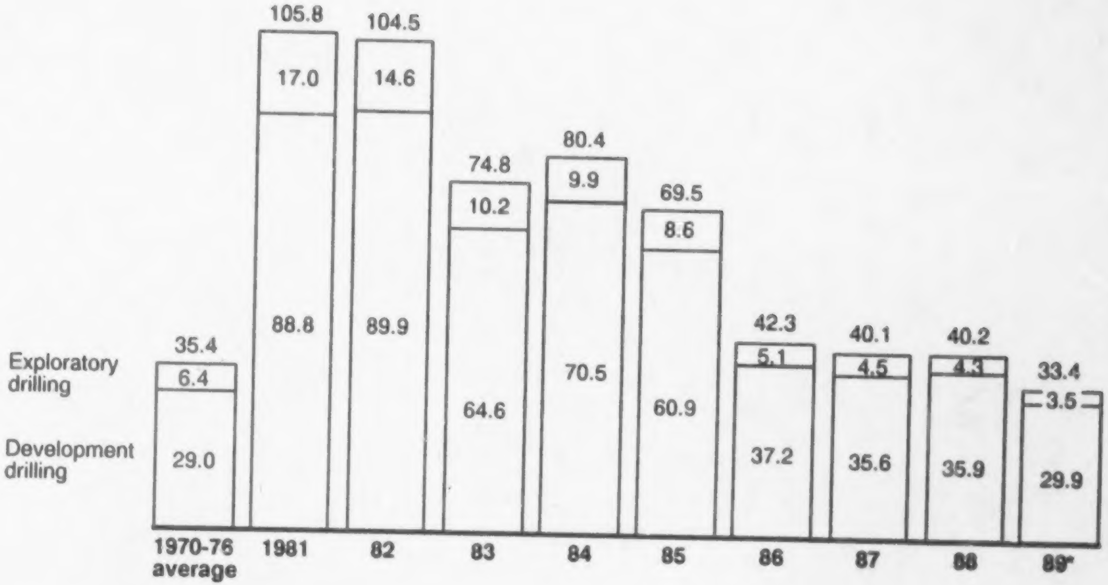
* * *

In summary, the transition in gas markets is not far away and will probably not be smooth. Even as many observors acknowledge the potential disruptions associated with the end of the gas surplus, industry participants have been unable to break out of the log-jam created by the past decade's gas bubble. Consumers would benefit from all industry participants and state and federal regulators taking steps to make the transition as smooth as possible.

Exhibit 1

GAS DRILLING ACTIVITY

Millions of successful gas feet



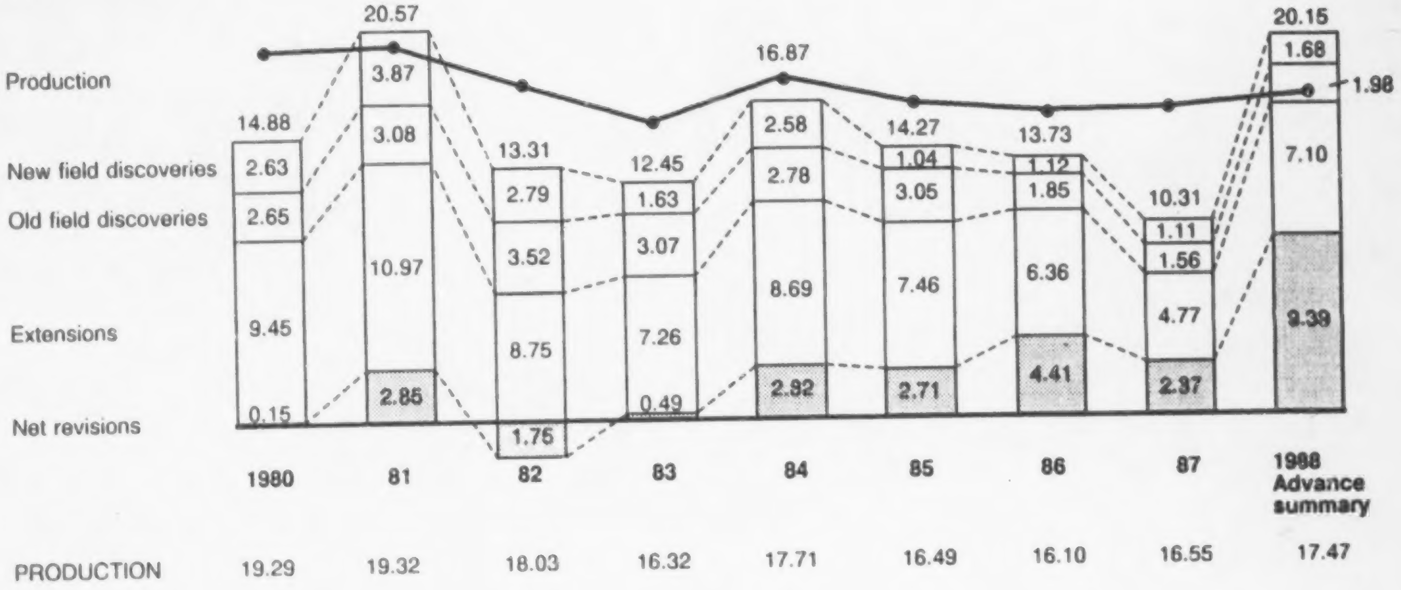
* Estimate based on first quarter

Source: API Quarterly Completion Reports

Exhibit 2

NATURAL GAS RESERVE ADDITIONS - LOWER-48 STATES

Tcf



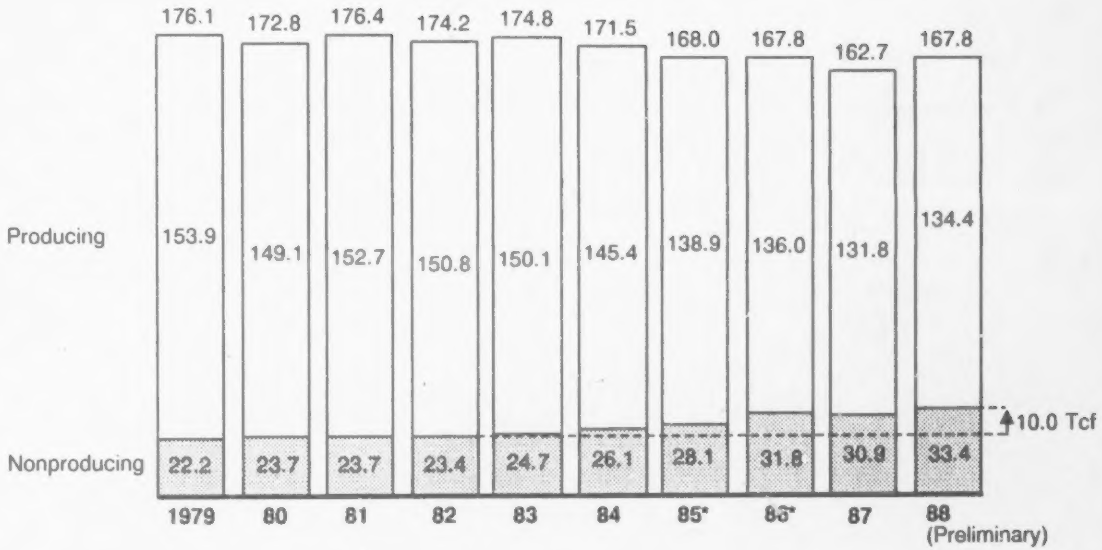
Note: Reserve additions do not include adjustments

Source: EIA; annual reports; McKinsey analysis

Exhibit 3

COMPOSITION OF NATURAL GAS RESERVES BASE - LOWER-48 STATES

Tcf

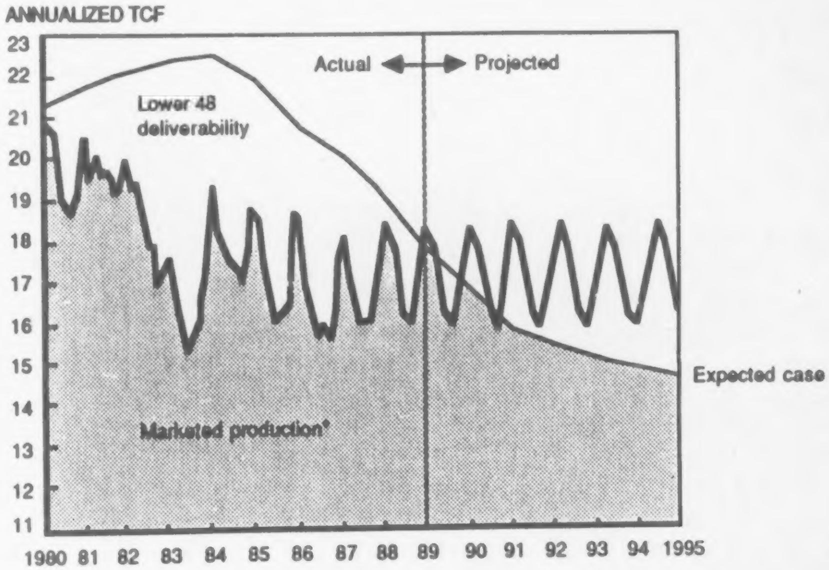


* Adjusted nonproducing reserves to remove swings in Wyoming nonproducing reserves

Source: API Quarterly Completion Reports

Exhibit 4

DELIVERABILITY VS. CALL ON LOWER-48 PRODUCTION - SUMMARY



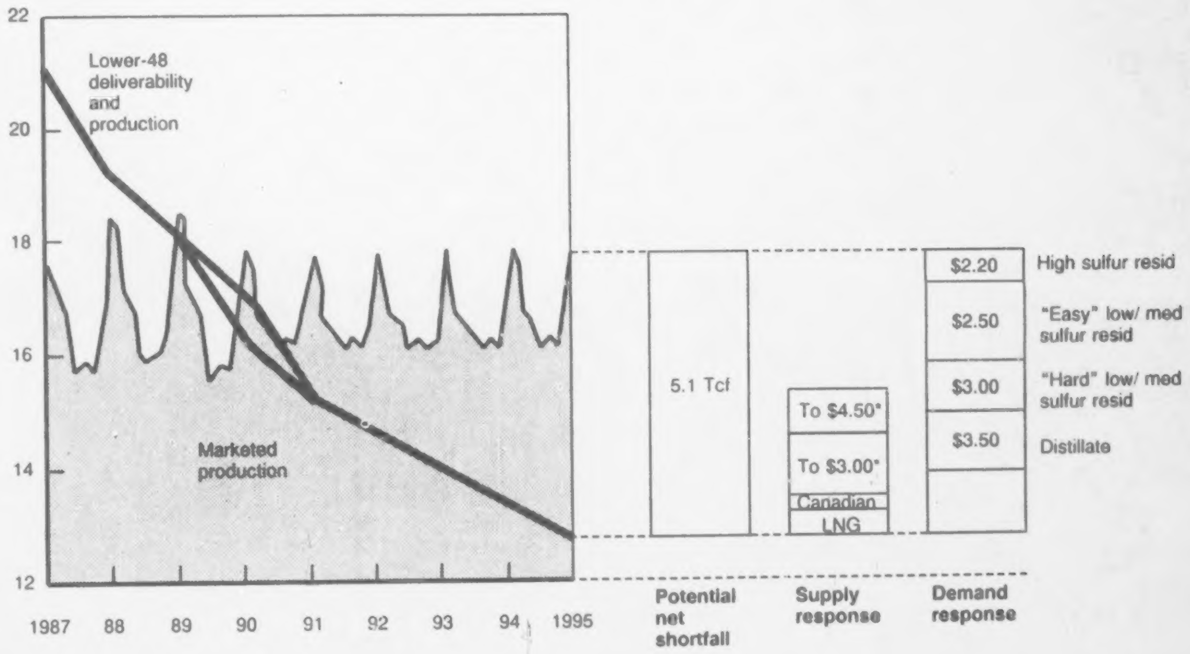
- * Projected marketed production equal to 1987/88 (for illustrative purposes)

Source: McKinsey analysis

Exhibit 5

POTENTIAL SUPPLY AND DEMAND OUTLOOK - WINTER 1995

Annualized tcf



* Incremental supply from Lower-48 reserve additions at indicated gas prices

Note: All prices in constant 1987 dollars; alternate fuel prices based on $17 crude

Source: EIA; PI; D&D; McKinsey analysis

Senator BINGAMAN. Thank you very much.

Mr. Lay, we are very pleased to have you here. Go right ahead.

STATEMENT OF KENNETH L. LAY, CHAIRMAN, ENRON CORP.

Mr. LAY. Mr. Chairman, thank you very much for inviting me and us today to discuss this issue.

Obviously, Mr. Sawhill has painted a fairly bleak outlook. I am not sure I would want to participate in an industry that had that kind of outlook. And so I hope, in fact, that our outlook is a little brighter than that.

About a year and a half ago my company—of course, hears from a lot of consultants, including Mr. Sawhill's group—but one of our consultants did come up with a very pessimistic supply-demand forecast well into the next century. This was not the McKinsey forecast.

Obviously, being primarily a natural gas company, in all the different aspects of the gas industry, it is very important to us in our financial planning and our strategic planning as to what we think the future supply-demand outlook and price outlook is. So we undertook within our company a fairly extensive, what I will call, a bottoms-up approach to trying to do our own estimating of the resource base and the supply-demand outlook.

We brought together a team of some of our best reservoir engineers and geologists, both in our explorations and production company and our pipeline company. And as you know, we do purchase and transport and sell more natural gas in the U.S. than any other company, so we do have a fairly extensive level of experience on the reservoir engineering aspects of all the basic producing regions in the country.

And of course, from that, we used a number of different modeling approaches to try to come up with our best guess under different scenarios as to what we thought the next 10 or 15 years might look.

I will say at the outset that our conclusion is quite different than John's. He may not agree with the first part of that.

We further confirmed, at least to our satisfaction, that the U.S. natural gas resource base is extensive. We think a good portion of that is, in fact, producible at very economic prices. And we think there is adequate supply and we think the economics will be such that it can support a growing market, particularly in the latter half of the 1990s and beyond.

We think natural gas will remain economically competitive with other fuels, with maybe some seasonal periods when, in fact, that will not be true and, in fact, will continue to be a very economically attractive fuel for a lot of electric generation needs, and particularly with the increasing concern on the environment.

First, as to the resource base, our own estimate of the resource base in the lower 48 states is about 650 trillion cubic feet. That is the potential resources, not the proved resources. This is, of course, very comparable to the estimate of the Potential Gas Committee. I think their estimate is a little bit less than that.

And it is kind of interesting, to me at least, as I have gone through and looked at our estimate by field and by different types of drilling, we come to quite different conclusions than the Potential Gas Committee, but yet the total over the whole country is very comparable.

That number is somewhat lower than the number that Secretary Henson Moore used this afternoon, but not substantially lower.

Having developed the resource base, we did do our own supply-demand evaluation. For the supply side, in particular, we used a model developed by the Energy and Environmental Analysis Group here in Washington, which has done extensive work on compiling producing and drilling and reserve data, again, by region, across the country; we think one of the more comprehensive supply models available.

Originally, a lot of the work on that was done for the Gas Research Institute in the early 1980s. But it does allow individual companies or other people to plug in their own assumptions and play different scenarios off, one against the other.

In our base case we did assume that something like the President's clean air proposals would be enacted and, of course, that there would be some major pressure to use cleaner fuels, and certainly co-firing, which Senator Ford talked about today and you have talked about, and some use of gas for vehicles and other purposes.

In our base case, assuming world oil price into the U.S. of about $27 a barrel by the year 2000, in real terms, in today's prices, or about 20 percent higher than today, and with some push toward the environmental aspects, we estimate the U.S. gas market at about 19.5 trillion cubic feet, both supply and demand, in the year 2000. Somewhat above current levels, obviously, somewhat lower than some other estimates, but certainly adequate for a growing market.

And I will say that that does include a little less than 2 TCF out of Canada, compared to the current 1.3 or so TCF out of Canada, and does include about 700 billion cubic feet of LNG, which John mentioned. But, obviously, still some good, strong Lower 48 production of about 16.5 TCF, which is at or a little above what we have experienced in recent years.

We estimate that if there was no push for a cleaner environment and no incentives to use cleaner fuels, that 19.5–TCF market might be closer to the 18.5–TCF market. We further estimate that if, in fact, oil prices stayed basically flat in real terms with today, we might be closer to a 16.5–TCF market, or very close to recent levels.

So, clearly, the supply-demand outlook is sensitive to and responsive to both national policy on the environment, but more importantly, on the economics, and particularly the alternative fuel price of oil.

Let me also say, though, building in, in our case, unlike I think DOE's case and others', we have built in some fairly significant increases in real drilling costs.

Of course, drilling costs are abnormally depressed right now, we believe.

We have built in about a 50 percent increase in real drilling costs to get to our 19.5 trillion cubic feet supply-demand balance of the year 2000.

If, in fact, that could be reduced to about a 20 percent real increase, which is not unrealistic with technological advances throughout the service business, the 19.5–TCF market, our base case, could well go to about a 21–TCF.

And, obviously, another way of achieving a much larger gas supply-demand, other than more efficient drilling and other services, where we can find and extract the reserves cheaper, would be a national tax policy. I mean a tax credit or some other instrument to make drilling costs somewhat cheaper could also get us to that 21–TCF-type market.

But in all of our cases, across all these four scenarios, natural gas remains competitive with residual fuel oil, pretty much throughout the period. Gas is competitive with coal in many markets in an all-in basis, if we consider both capital investment as well as operating costs—not in all markets, but in many markets.

Across all cases, of course, the higher prices or lower costs elicits a significant supply response. And again, keeping in mind that our modeling work looked at this more from a standpoint of a producer and a pipeliner—that is looking at the economics of making the investments versus some more simply regression-type analysis.

We do look for the imports from Canada going up from about 7 percent today to about 10 percent by the year 2000, and with 3 or 4 percent of our total market supply coming from LNG.

The policy implications, from our standpoint: we think the resource base is there. We think, with reasonable economic conditions, there being somewhat higher oil prices and/or somewhat larger incentives for drilling for domestic gas, there will be adequate supply from the mid-1990s on, to meet the market and to provide a larger role in cleaning up the environment.

Our base case would show about an additional 2 TCF of gas going into electric generation through co-firing and gas-fired combined cycle and cogeneration in order to achieve the President's clean air objectives.

Of course, another key element to make sure that that does happen is reform of the Public Utility Holding Company Act, which Senator Johnston has introduced a bill to that effect in recent weeks, so that, in fact, independent producers can participate in building gas-fired combined cycles in those markets where the economics justify it.

I will say that we agree with John Sawhill in the short- to intermediate-term, that, indeed, because of the very low drilling activity over the last four years now, and with the increasing demand for electricity, we well may see a very tight gas market over the next two to five years as, in fact, the supply and demand do come into balance, and during a period when, in fact, there will be some lag from a tighter market and somewhat higher gas prices, until we do see some response on the supply side.

But with the resource base and with gas prices coming back into parity with alternative fuel prices, and with some gradually rising oil prices in the 1990s, we do not see any problem beyond the mid-1990s in serving a growing market.

And in our conclusions, we have conducted a fairly in-depth analysis of the U.S. natural gas supplies, we have concluded there is a very large resource base. We think that most of this resource base is economically recoverable at reasonable prices. We do expect prices to rise from today's low levels.

I will say, under our projections, by the year 2000, in real terms, natural gas prices at the wellhead, and more importantly, to the residential consumer, would not be much above where they were in the early 1980s, but obviously above where they are today.

We believe that with the very efficient gas-fired combined cycle plants, gas will be very competitive with alternative types of generation. And with both the economic and the environmental incentives, natural gas will, in fact, be used for an additional percentage of our total electric generating load.

We believe there is some need for some legislative and regulatory reforms. We are certainly very encouraged by some of the reforms that the Secretary discussed before our panel. But we believe, with those reforms, and hopefully with not too many more relapses, such as the 451 reversal, that natural gas will play a leading role in serving the nation's energy needs well into the next century.

And with that, I will shut up and we will get to the questions.

Senator BINGAMAN. Mr. Sawhill, did you have any additional comments on anything Mr. Lay has suggested?

Mr. SAWHILL. No, I do not think so.

Senator BINGAMAN. Let me ask a couple of questions here. Let me just announce before I start asking questions, I think what we will do, in order that we can speed this up and get to the other panel that we have got also, is to limit each Senator to about five minutes on the first round. And then if there are Senators with additional questions, we can come back and do another round.

Mr. Sawhill, the exhibit you have given us, Exhibit 4 and Exhibit 5 in particular, showing a significant shortfall this next winter, I gather there is no real disagreement between the two of you on that issue?

Mr. Lay, did you mean to suggest that you agree that there will be a significant shortfall this next winter?

Mr. LAY. I think again we may be talking about degree more than we are absolute results here. I first of all would not use the word "shortage." I do not think we will see shortages.

I think if we had a very cold winter—and we have not had a colder than normal winter for quite a few years, as you know, Senator—that in fact there might even be some regional dislocations. But I am convinced that there is enough flexibility in the system from the storage and from other ways of moving the gas around the country that in fact, except for the switchable load, we will have no problem serving our gas markets this winter or next winter or any time in the next two or three years.

I do think markets are going to get tighter. I think there will be a lot of people that in fact have switchable capability that are going to find the need to switch for economic and other reasons. And I think it will be some time before we can get back to the point where everybody that is currently using gas will be able to use all that they want.

But I do not see shortages. I think the market is a lot more efficient and a lot more flexible today than it was in the late seventies, and I think with that flexibility we will be able to work through this period without certainly any dislocation for the residential, commercial customers, and very little dislocation for even the priority and industrial customers.

Senator BINGAMAN. Mr. Sawhill, as I understood your testimony, you had indicated that you thought this shortfall would drive the price of natural gas above three dollars, significantly above three dollars per mcf this next winter?

Mr. SAWHILL. Well, I am not sure about this next winter. I would basically agree with the statement that Ken Lay has just made about what is likely to happen this winter.

By the way, there is a tremendous impact the weather can have. The difference between a warmer than normal winter and a colder than normal winter could be as much as one or one and a half tcf of gas, which is a very significant portion.

So if the weather were very warm, I doubt if we would even notice any disruption in market conditions at all. Last winter, for example, was a relatively warm winter. We had a few little problems in California, a few days of tightness in Texas, but very little other disruption.

And I think next winter may be the same thing if it were warmer than normal. On the other hand, if it were colder than normal I think we would see a lot of switching from gas to oil. It is possible that there would be times when some gas users would not be able to get supplies. I do not think it would be as severe as we experienced say in 1977, when we had schools and hospitals closing. But I think there could be some disruptions in the marketplace. I guess I am not quite as sanguine about the flexibility of gas markets. It seems to me that you have got a pipeline system that admittedly is a lot more flexible than it was in the early 1980's, but there are still gas reserves that cannot move about the country as freely as we could if we had more flexibility in our pipeline system.

In the Rocky Mountain area, for example, and to some extent in the mid-continent area, there just is not enough pipeline capacity to get that gas to the highest value markets.

Secretary Moore in his testimony talked about the need to speed up the certification process so that we could get some of this new pipeline capacity built, including pipeline capacity from Canada, and I would certainly agree with that.

Senator BINGAMAN. Let me ask either of you that have an opinion on this. The FERC has cleared the way so that we could have the Commodity Futures Trading Commission approve an application for the New York Mercantile Exchange to establish a natural gas futures market. Is that something that will be helpful, harmful?

What will the effect be if we have a natural gas futures market?

Mr. LAY. Mr. Chairman, I think as we go to a more competitive market there will be increasing pressures among both buyers and sellers to find some ways of hedging the future, as we have seen in other volatile commodity markets, and so I think eventually we will have different ways of hedging the future, whether it be this futures market, whether it be different contracting techniques within the industry.

And I think there is some of that going on now with our company and other companies. But I think there is going to be a need for ways to hedge future markets.

Now, let me say, having said that, having looked at, as we all have, looked at the oil futures market over the last few years, it is hard to say that the futures market stabilizes prices. If anything, it probably makes prices more volatile.

So at the same time that there may be a pressing need for ways to hedge the future, futures markets also might make gas prices even more volatile than they are now.

Mr. SAWHILL. I guess my view would be that, as Ken said, we are probably likely to have a futures contract. I am not sure it is going to have all that much impact, because I see the gas market evolving into a lot more very long-term contracting, five and ten-year contracts that producers will sign with pipelines and end users.

I think increasingly as we move into tighter gas markets, the local distribution companies are going to recognize that security of supply is very important to them and they are going to be willing to pay a premium for long-term supplies.

And it is this kind of contracting mechanism that I think will be introduced into the industry that goes far beyond the range that we will see in the futures market.

Senator BINGAMAN. I believe my time is up. Senator Nickles.

Senator NICKLES. Mr. Chairman, thank you very much. It is an interesting discussion. I appreciate the panel's comments. They are in a little different direction. Mr. Lay, you mentioned that the increased consumption, I think I heard you say that, under a different scenario is due to environmental concerns and the growth in the economy, but you thought we would be around 20 trillion feet by the turn of the century, someplace like that?

Mr. LAY. I think our base case is about 19½ trillion cubic feet, Senator Nickles. But I said with some improvement in the service technology and of course the efficiency of drilling and locating natural gas. That well could be, or with some change in tax policy, some additional incentives to encourage the drilling for natural gas, why, that well could be 21 tcf or so.

Senator NICKLES. But most of that increase, as I was hearing you say, would be supplied either by Canada or by LNG?

Mr. LAY. A good bit of the increase will come out of Canada and LNG. Well, in the base case domestic production is reasonably stable with where it is today. But I think on the flip side of that, I think there have been a number of forecasts that show domestic production declining over the next ten years.

Now, under again the enhanced drilling case or the tax credit case, why, there could be another one and a half or two tcf of domestic production.

Senator NICKLES. I think I heard both of you allude to where, you did not use the word "bubble," but the term has floated around the industry and for the last six years people have been predicting the bubble is going to disappear in two years.

I heard you say, Mr. Sawhill, you think that the bubble is going to disappear next year.

Mr. SAWHILL. Yes, as a matter of fact I think it is gone right now.

Senator Nickles. Would you agree with that?

Mr. Lay. I agree with that. I think in fact that on an annual basis supply and demand have been basically in balance for at least the last year or so. Again, we have had the mild winters and other things that have created at least the appearance of a lot of surplus during certain periods of the year.

Senator Nickles. Well, we have in my state and I am sure in some of the other states, a lot of gas that is still shut in and we have a lot of producers that are sitting on gas waiting for that bubble to disappear. They are waiting for somebody to buy that gas.

They are waiting for somebody to be able to buy that gas. They are negotiating with pipelines, Enron and others, to buy that gas. And many have been praying for that cold winter to come about to get demand in equation with supply, I guess.

But both of you think that that is just about here. We really have not seen that in the price equation yet.

Mr. Sawhill. No, prices have actually in recent months been very soft, although they have bounced around. You know, if you look at the comparison of this year's prices and last year's prices, one month they are a little higher, the next month they are a little lower, but they certainly have not had any sustained rise.

I do think we will see that as winter approaches, particularly if it looks like the weather is going to be colder. But I would have to agree that we have had no indication of it.

My own view is that in commodity markets, though, you do not get a gradual and smooth price transmission; you get fairly sharp transitions. And so I think prices will move up and they will move up fairly sharply.

Senator Nickles. Would both of you agree with my prediction, or at least my assessment? I have been stating to people that proven reserves were a great buy. Right now they can be bought in many cases very cheaply. And I cannot help but think that in a few years that there would be significant appreciation.

Mr. Lay. Senator, again the price for reserves in the ground, it is kind of the markets are sending different signals right now, because the prices for the reserves in the ground have increased rather significantly this year versus last year.

And even over the last few months, they have increased. And at the same time, prices in the marketplace are lower this year than last year and have been declining over recent months.

Now, that might suggest that the people that are buying reserves in the ground is quite a different department in many companies than the people that are selling gas out of the ground.

Senator Nickles. Would you agree with my assessment that natural gas is priced as a commodity right now, which is what, we have spot gas in my state going for what, $1.30 or something in that category, would be significant room for appreciation when that "colder winter" hits, maybe this winter or next winter, and you actually see some pull from the demand side?

Mr. Lay. We think so. But again, there is a lot of disagreement on that or else the prices would not be where they are now. There are still some people that believe that we will have a gas surplus for several more years.

Senator **NICKLES**. Thank you.

Senator **BINGAMAN**. Thank you very much.

Senator Ford.

Senator **FORD**. Well, if the old folks are right we are going to have a cold winter.

Mr. **LAY**. We hope they are right, Senator. [Laughter.]

Senator **FORD**. There has been a lot of haze. You know, you get up there, there is a lot of haze out there, and the leaves are falling before they turn brown, and the wooly worm is putting on a heavy coat. So that judgment may be as good as some of the others that I have heard. [Laughter.]

We have been living by the old folks for a long time.

Mr. Lay, you remind me of Harry Truman when he wished he had a one-armed economist. You said on the futures markets, in a way it could stabilize it and then on the other hand it could frustrate it.

Do you believe the future markets will help or hurt?

Mr. **LAY**. I did not say "stabilize," and in fact I think there is going to be a lot of pressure to have something where you can hedge future prices.

But I think if past experience holds out, it still may make the market more volatile on a day-to-day basis.

Senator **FORD**. So you would say the market would be more volatile? You would come down on that side?

Mr. **LAY**. Yes.

Senator **FORD**. So we would not need the other hand.

Mr. **LAY**. On that issue. [Laughter.]

Senator **FORD**. Well, we are going to get into a lot of issues. I have only got five minutes. I can get to a lot of them in that time.

You made a statement about the deliverability and shortage and that sort of thing, and we talked a little bit about shortage in California and some in Texas. You have natural gas, but you cannot get it to your customer when he needs it, and we have had that shortage.

And then if I understood you correctly, trying to make notes very quickly and listen to what you say, you said over a period of time you get back to a point where we will be able to deliver it smoothly.

Did I understand you correctly?

Mr. **LAY**. You did, Senator. I think the——

Senator **FORD**. Then how long would it take us to get back to the point where we could deliver it smoothly? How much more distribution systems? What kind of pipeline proposal? What of those things are necessary to get this huge surplus of natural gas that is going to be the fuel of the future?

You will hear that in testimony after you this afternoon, that gas is the fuel of the future, and everybody that is drilling hopes the hell it is, you know. But they also are realists and say it will not last that long.

Mr. **LAY**. I think you are saying get it back to a smooth system. I think more importantly my comments were to get it back into a growth mode, I mean where in fact we could serve growing markets again.

I think we may have a period of two to five years in here where in fact the markets will need to stabilize until we get the supply to catch up with the growing demand.

But again, my main point on the shortage question was there may be a lot of people that are buying spot gas, buying interruptible gas, that during this period of time are not going to be able to get that all the time they want it. And that is mainly power plants and industrial plants.

But as we found last winter in Dallas, I mean there is even a school system that bought interruptible gas. Now, the key thing about interruptible gas is it is interruptible, and we may see some of that the next few years for those people that have been buying interruptible gas to get it cheaper.

And of course, as markets tighten up those will be the first people that will be shed off the system. So we may see some of that.

Senator FORD. You are saying to me that you may have the gas, but you do not have the capability to deliver for the next three to five years?

Mr. LAY. But I think the supply is the key there, even more so than the delivery capacity. I mean, the main problem is in fact the gas deliverability that will be available.

Senator FORD. Well, the deliverability I am talking about is the ability to get it to the residents or to the industry and that sort of thing.

Mr. SAWHILL. No, I think Ken is trying to make a different point. It is not—the fact is that we have not drilled enough so that we have the capability of getting it out of the ground, producing it. We have got to drill more.

Too much of our gas is in non-producing status. We have got to drill more in order to produce more.

And we also have to build more pipelines. So there are really two issues here, building the pipeline capacity from areas where we do have surplus gas, like the Rocky Mountains or in Canada, and secondly drilling more wells so that we have the capability of producing the reserves that we have already proven.

Senator FORD. Well, deliverability to a consumer and your deliverability are two different things. And we listen to the consumer, and so I talk in consumer language and I hope you understand that.

But what caused the shortage and inability to deliver the gas recently in California and Texas?

Mr. LAY. Well, let me first take California. And, in any question like that, there is no simple answer.

Senator FORD. Make it simple, will you, so that I can understand it.

Mr. LAY. Well, primarily in the case of California, they had not put as much in storage prior to last winter.

Senator FORD. Who are "they" now?

Mr. LAY. The utilities out there. And, again, we had some unusually cold weather and so it did not work out too well.

Senator FORD. So, they did not have it to give to their customers or deliver to their customers?

Mr. **Lay**. And there were some of the same phenomena in Texas and, again, keep in mind, Senator, that in both states and, of course, across the country again, the utilities, the distribution companies have increasingly become dependent on spot gas, on interruptible spot gas, and it is very difficult for the economics to work in putting gas in storage to serve customers that are going to buy all their gas or a lot of their gas on a spot interruptible basis.

I think we see some shift in that now.

Senator **Ford**. I see my time is up, but just is Canadian gas controlled, the price controlled in any way?

Mr. **Lay**. It is not, and under the free trade agreement it is very much of an arm's length negotiated transaction type market now.

Senator **Ford**. It is like pork coming over here. It hurts the farmers.

Mr. **Lay**. Well, it may hurt the farmer, but it also may help the consumer. I am trying to talk in consumer language too, Senator.

Senator **Ford**. I understand that. I understand that very well. The time will come when both of us will have our problems.

Senator **Bingaman**. Senator Conrad.

Senator **Conrad**. Thank you, Mr. Chairman. Like Senator Nickles, we in North Dakota have a lot of gas to sell. I am not so certain that we are eager to have a real cold winter in order to sell it. We are willing to do a lot of things to get that gas sold, but that is perhaps not one of them.

I was interested in your outlook on price, both Mr. Sawhill and Mr. Lay. We have got a spot price that I understand we are around $1.50 on a spot price now, somewhere in there, and, Mr. Sawhill, you are talking about going to $3. What is the time frame on that?

Mr. **Sawhill**. Oh, I think over the next two to three years.

Senator **Conrad**. And, Mr. Lay, what would your price outlook be in that time frame?

Mr. **Lay**. I would like to believe Mr. Sawhill's price outlook, but ours is not quite that from my standpoint optimistic. I mean, I think as markets come into balance, we hope this winter, I think we will certainly get back in parity with residual fuel oil which will move the prices on the average back up to the $2, $2.25 range, and I do think with some increase in oil prices, we will see $3 prices at the wellhead in the not-too-distant future. But that, again, is going to be largely dependent on oil prices.

Senator **Conrad**. Are we talking apples and oranges here? Your $3, Mr. Sawhill, in the next two to three years, is that the wellhead?

Mr. **Sawhill**. Yes. So, we are talking apples and apples.

Senator **Conrad**. You are talking about getting to $3 in that time frame?

Mr. **Lay**. I am talking about getting to $3 probably more like over a five or six-year period under our forecast.

Now, again, for the basis of our modeling we have assumed about a 20 percent increase in real terms in oil prices between now and the year 2000 and about a 25 percent increase in real terms in gas prices.

Senator **Conrad**. I understand that. Let me ask this, Mr. Lay. What would lead you to be off substantially in your price projection if there is one factor or two factors that would alter substantially by a factor of 25 percent or more your outlook?

Mr. LAY. I think the first thing would be oil prices. I mean if, in fact, oil prices are substantially higher or substantially lower than we are forecasting, then it will have the same kind of impact on natural gas prices.

Senator CONRAD. And your weather outlook is based on sort of a steady state standard winters that we encounter being relatively mild in North Dakota?

Mr. LAY. From the standpoint of a longer term forecast, we are not making any assumption about abnormally cold winters. We are assuming reasonably normal type seasonable patterns. And you are right. North Dakota tries to do its share on winter every year. [Laughter.]

Senator CONRAD. And do.

Mr. LAY. And we sell some gas up there.

Senator CONRAD. Thank you, Mr. Chairman.

Senator BINGAMAN. Thank you very much.

Senator Ford, did you have additional questions for these witnesses?

Senator FORD. I have a lot of them, but I have a 4:00 appointment.

Senator BINGAMAN. Well, let me thank both of you very much. We appreciate your testimony, and we may think of some additional questions as we cogitate about it.

We appreciate it very much.

The final panel—let me ask them to come forward—Mr. Arlon Tussing, Mr. George "Bud" Lawrence, Mr. Nicholas Bush, and Mr. Danny Conklin.

Gentlemen, let me urge that each of you summarize your statement if you would and you should do so briefly, and then we will see if there is still time for questions.

I hope there will be some time for a few questions, but we appreciate very much your being here, and we look forward to your point of view on this issue of supply and demand for natural gas in the 1990s.

Mr. Tussing, why do you not go right ahead.

STATEMENT OF ARLON R. TUSSING, PRESIDENT, ARLON R. TUSSING & ASSOCIATES, INC.

Mr. TUSSING. I am Arlon Tussing. I am President of Arlon R. Tussing & Associates.

I was the chief economist of the Senate Interior Committee, the predecessor of this committee during the seventies and was an in-house consultant for several years before and after that, and so I am familiar with being back on the other side of the podium, and I am delighted to be back here.

I serve as an advisory consultant to producers accounting for about 80 percent of U.S. oil production and about half of U.S. gas production to four of the top ten interstate pipelines. Half of the ten largest utility companies in the United States and to several state commissions and consumer organizations, and my remarks here are—I have a prepared statement which is a little technical, and I hope you will bear with me as you read through it.

I did attach, however, a paper I presented in Caracas in June called "Perspective on World Energy Markets" that sets out a case for a rather optimistic viewpoint both about fossil fuel supply availability in the long term, course of prices, and the early availability of clean non-fossil fuel sources.

One part of my perspective is that natural gas is the strategic source of primary energy for both the United States and for the world for the next decade or—and probably well into the third millennium, but that we are close to a breakthrough on a number of alternative non-fossil, clean energy modes which will tend to be cheaper as well as more environmentally benign than our traditional energy.

As far as supply is concerned, natural gas is the most abundant hydrocarbon in the earth's crust. When we talk about proved reserves or commercial resources or resources of conventional gas, we are talking about only a tenth or a hundredth or a thousandth of the actual methane that is in the earth's crust, and the bulk of the methane that is classified as reserves either indicated or potential are those that are in either oil reservoirs or something analogous to oil reservoirs.

And the ultimate resource is so stupendous, however, that there is really little point of treating it as an exhaustible resource.

Now, I preface this to say that for the purpose of saying to beware of the forecast and models or the results of elaborate computer models. The track record of the professional forecasting profession and of the forecasting agencies of the federal government and industry and the universities and the like has been abysmal.

That the more experts one hired during the 1970s and the more one paid attention to these sophisticated models, the more misled one was to be.

I say this. It is not in my prepared remarks. Because of the inordinate weight, it seems that Secretary Henson Moore put on the results of data surveys and data processing.

There is virtually nothing that a complicated model will give you in terms of decision making and, hence, your decision-making capacity in complicated issues. They miss what is most important.

The complicated models of the 1970s miss the fact that oil was a cyclical commodity industry, that long-term costs of oil production is downward, not upward, and a whole series of other things that were crucial to the results in which the details of the model were misleading.

I also recall one study of the 1970s performance of various electric demand forecasting models, and the result was that one can reliably predict—one could reliably predict—the performing forecast or the forecasting performance. The more complicated, the more equations in the model, the worse its performance.

Anyway, the natural gas industry in the United States has undergone a virtual revolution in the last six to eight years. It has changed from a bulkanized—that is a fragmented collection of regulated utility entities—to an articulated network of highly competitive markets.

The production market, the primary extracting sector and the first sale market for natural gas are as close to perfectly competitive textbook models of commodity markets as we can find.

We have the market is now dominated by a spot commodity market in which there are public and transparent and reliable price quotations that vary day by day and in which the daily, weekly, monthly variation of prices tends to balance supply and demand.

It is an industry that is vastly more efficient than the industry we had ten years ago. In the 1970s the Federal Power Commission and the representatives of the American Gas Association, the Interstate Pipeline Association talked as if the normal situation, the normal reserve backing to avoid delivery crises in the United States was 20 years of reserves. With the flexibility that went along with less regulation with both price flexibility and the end of dedication, that is the end of contractual and mobilization of gas.

1981, which was the year curtailments ended, we got down to a reserve to production ratio of less than 8. That is, this is an industry that utilizes its resources much more effectively.

Somebody mentioned the year of 1977. In January of 1977 when were there curtailments of firm demand throughout the Midwest and Middle Atlantic states, 6 percent of the gas we produced in the United States went to ammonia urea plants and 12 percent went to power stations. In two states alone, power stations with alternate fuel capacity, there was just the—neither the incentives, the pipeline hookups nor the institutional arrangements existed to get the gas from those who valued it very little.

The ammonia producers, for example, added less than 25 cents per 1,000 cubic feet to the value of the gas for producing ammonia, and so at a premium above the existing intrastate price, you could have solved the shortage in the Midwest.

That is not going to happen anymore. We have a flexible commodity industry in which there will be local dislocation. There will be tightness and surplus at times. So long as we maintain deregulation, so long as there is no certification—that is, there is no regulatory approval of contracts—as long as buyers and sellers can do what is in their interest.

We do not face any systematic national shortage or any systematic national surplus.

Now, as to whether the bubble is over or not, I would say we are now in a situation where we have simultaneous shortage and surplus, but it is not because of the inefficiencies in the primary producing sector or the regulatory impediments there. It is because the move to competitive markets that has almost totally swept the producing sector and the first sale market does not extend downstream that the downstream delivery infrastructure, the pipelines, the local utilities delivery facilities and that include storage is still subject to inflexible prices that do not clear the market.

As prices are set by regulation on the basis of formulas that have nothing to do with supply and demand, the capacity is immobilized through something akin to the kind of dedication of reserves. That is that those who have transportation rights on a pipeline or utility cannot—they have an incentive to hoard them even though they are having to pay for them because once yielding them up, they are going to lose them.

And in many cases holding onto this capacity, even if it is not used, enhances the market power of the various parties so that we do not have a spot market in transportation capacity.

In my prepared statement I make two suggestions as to what the FERC can do to resolve the remaining inefficiencies, imperfections and inflexibilities in the delivery system. And these are things that, if FERC is unable or unwilling to do, Congress should consider mandating.

Senator BINGAMAN. If I could ask you to summarize those quickly. I am afraid we are going to run out of time before the other witnesses get their chance to testify.

Mr. TUSSING. The first is to do away with the hybrid regulated merchant function of the pipelines. The buying and selling of gas is an inherently competitive function. There is no need for any FERC involvement.

The regulated supply amounts to only about 30 percent of total throughput today, yet it commands something like two-thirds of the firm capacity on the pipelines and it utilizes something like 90 percent of FERC's attention.

There should be a clean split between transportation, which will continue to be regulated, and sales, for which there is no need for further regulation.

The second thing is that transportation capacity, once obtained through some allocation mechanism, should be freely assignable, should be transferable, subdividable. Pipeline customers, as such, have no monopoly power and FERC should not regulate or attempt to set up rules for capacity brokering, much less than what FERC does now is to restrict them.

I think the final point I have to make is that nobody knows, nobody has the information to decide what new pipeline capacity is necessary. There are enormous distortions in the price signals that they are getting. I believe that the amount of new capacity into California or into New England is much exaggerated by the immobility of the existing capacity, and the fact that it is not priced at its value during the seasonal peaks.

So that the first task of the FERC, with respect to these provisions, is to provide for the pricing and allocation mechanisms that will allow either the FERC, or preferably the private sector, to decide what investment should be made.

[The prepared statement of Mr. Tussing follows:]

The Tasks of Public Policy with Respect to Natural Gas

COMPLETING THE TRANSITION TO COMPETITIVE MARKETS

Prepared Testimony of

ARLON R. TUSSING

Before the

United States Senate
Committee on Energy and Natural Resources
Subcommittee on Mineral Resources Development and Production

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The Tasks of Public Policy with Respect to Natural Gas

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Introduction

Natural gas will be the chief strategic source of primary energy for the U.S. economy over the next decade and most likely well into the next Millennium. Some of the reasons for my judgment are set out in an earlier paper, "Prospective on World Energy Markets," which I have appended to my prepared statement. I shall confine today's statement to what I believe are the immediate tasks of public policy with respect to natural gas.

The Outlook for Natural Gas

The Uses of Gas

Natural gas will play an indispensable role in bridging the transition to clean, non-fossil sources of primary energy. Gas-fired combustion turbines are, for example, superior to coal or nuclear-fired steam plants in almost every economic dimension --- capital cost per kilowatt, thermal efficiency, minimum economic scale, construction time, and reliability. Of all the combustion resources, moreover, gas contributes the least to global carbon-dioxide emissions, and is cleaner with respect to most other pollutants.

The Supply Outlook

Natural gas is the most abundant hydrocarbon in the earth's crust. Tiny molecules of methane are far more mobile, moreover, than those of crude oil or, of course, coal, and are thus able to move to and permeate the spaces in a vastly greater variety of rocks or deposits of sand. The bulk of the methane thus far classified as a "fossil fuel", booked as natural-gas reserves, and produced commercially has been found in petroleum reservoirs or geological structures closely resembling such reservoirs. The ultimate methane resource is nevertheless so varied as to defy definition, and so huge as to defy quantification.

Since the mid-1970s government and industry forecasters have had a near-perfect record of underestimating the deliverability and overestimating the replacement cost, of natural gas. In 1981 hearings before the predecessor of this Subcommittee regarding the proposed Alaska gas pipeline, a consortium of major producers, pipeline companies and gas utilities, together with the Department of Energy, sponsored testimony that predicted a 1990 market value of natural gas about **ten times** today's free-market price level!

This consistent record of defective predictions comes in part from extrapolating exploration results in an environment constrained or distorted by price controls, the economic immobilization of gas reserves (e.g. via their eternal "dedication" to specific buyers), and government-enforced monopoly control over transportation. It also stems from a failure to appreciate the steady addition to the menu of recognized geological targets for gas extraction, the steady decline in real costs of **inputs** to natural-gas exploration and production, or the steady advance in geological knowledge and extraction techniques.

The vastness and diversity of methane resources and the wide and growing menu of extraction technologies mean that small increases in anticipated prices can be expected to evoke larger increases in potential supply --- if not from conventional resources in the established producing areas of North America, then from deeper into the earth, from tighter formations, from the Arctic or the deep offshore, or from abroad in the form of LNG, methanol, synthetic gasoline, or other methane derivatives suitable for tanker transport.

Change in Market Structure and Regulation

From a Collection of Pervasively Regulated Utility Services to a Network of Vigorously Competitive Commodity Markets.

Over the last decade the natural-gas industry in North America has been changing from a balkanized collection of pervasively regulated utility services to an integrated network of vigorously competitive commodity markets. This transformation is now almost complete in the producing sector and in the "wellhead" or first-sale markets for gas, which are coming to resemble textbook examples of "perfect competition".

The associated changes in market organization and business practices have dramatically reduced the effective cost of gas supply, eliminated the regional supply and price disparities and the shortages that characterized the old regulatory regime, and insure against their return. Changes in supply and demand now generate the correct price signals, and direct them to the appropriate producers and consumers. These price signals can be counted on to balance the aggregate supply and demand for natural gas and to steer whatever supply is available at a given time to its best and highest uses with a minimum of government involvement.

The Critical Distinction Between Competitive and Natural-Monopoly Functions

The recent evolution of gas-market structure rests on a new public consensus that both the primary extraction of natural gas --- including its exploration, development, production, and gathering --- and its marketing are inherently and irrepressibly competitive activities. Both lines of business are carried on most reliably, efficiently and cheaply if there are no regulatory barriers to entry and exit, or restrictions on pricing and other terms of sale. Hundreds of sellers controlling thousands of wells are capable of competing for each final sale of natural gas, while thousands of purchasers are capable of competing for each such supply source --- **provided they have effective and equal access to the physical means of delivery**. In such an environment, competition is clearly a more effective tool than regulation for insuring the "public necessity and convenience" regarding the primary supply of natural gas, and with respect to the "justness and reasonableness" of first-sale prices for that supply.

This proposition was subject to bitter debate in the 1950s, 1960s, and 1970s, but no longer provokes serious controversy. The "natural-monopoly" elements that once seemed to justify pervasive regulation are now recognized as features of the **physical transmission and distribution of gas**, as opposed to its production or sale. To the extent economic regulation remains necessary, its function is to prevent control over essential transport, storage and distribution facilities from being exploited to monopolize or create undue preference in buying and selling of natural gas, or to undermine their flexibility and efficiency.

Thus, over the last decade two complementary themes have dominated both public policy and the natural evolution of market structure in the gas industry: (1) Deregulation of inherently competitive activities, production and marketing, and (2) drawing a clear distinction for purposes of market organization and regulation between such competitive activities and the physical delivery of gas, for which the traditional rationale for public-utility regulation retains some force.

Completing the Transition

Two main tasks of public policy remain with respect to natural gas at the federal level; accomplishing them will permit the private sector (with the assistance of state public utilities commissions) to discharge its responsibilities effectively.

The first of these tasks is to complete the separation between competitive gas-marketing activities and regulated transmission services by abolishing the regulated "merchant function" of the pipelines, which is now under the jurisdiction the Federal Energy Regulatory Commission ("FERC"). This regulated service is an anachronism whose direction and supervision consumes a disproportionate amount of FERC energy and attention, and whose very survival the Commission is able to perpetuate only by allowing the pipelines to restrict or cripple more efficient service alternatives. **The second task is to facilitate the creation and operation of an unregulated secondary market in those transportation services** whose primary supply is now (and probably must remain) subject to Commission jurisdiction.

Closing out the Interstate Pipelines' Regulated "Merchant Function"

Under the "old regime" shaped by the Natural Gas Act of 1938 and especially by the Supreme Court's 1954 Phillips decision, interstate pipelines functioned mainly as buyers and resellers of gas at regulated rates, as opposed to common- or contract carriers of shipper-owned gas. Throughout the 1960s and 1970s, more than nine-tenths of the gas sold in interstate commerce was purchased by pipelines under long-term contracts at regulated prices, and resold to local distribution companies at "bundled" rates made up of average ("rolled-in") gas-acquisition costs plus a regulated transportation markup.

Today's market, however, was shaped under the Natural Gas Policy Act of 1978. More than three-fourths of interstate gas sales now represent gas whose first-sale price is **not** regulated, and which is **not** purchased for resale as regulated "system supply" by the pipeline which first transports it but is, instead, transported by that pipeline on behalf of a shipper that is **not** subject to FERC regulatory jurisdiction, generally under a FERC-approved transport tariff. Such shippers include producers, local distribution companies regulated by state utility commissions, gas-consumers, and gas-marketing companies.

Despite the availability on every major pipeline system of "unbundled" transmission service, which ought to permit the various gas-industry participants to match supplies or markets with the required transport services in any desired combination, the pipelines continue to offer a combined "system-gas" sales service regulated by FERC. In most cases, moreover, FERC continues to permit or encourage the pipelines to use their power over essential transport facilities to favor this traditional, but inflexible and inherently inferior, service at the expense of marketing services offered by competing vendors.

While the proportion of regulated pipeline sales in total gas sales has shrunk dramatically in recent years and continues to shrink, a disproportionate share of the nation's **firm** transport capacity remains dedicated to these services, and thus unavailable to competitive sectors of the gas market. Not surprisingly, many pipelines will continue to offer and defend their traditional regulated sales service so long as it is a vehicle by which FERC allows them to hold on to a preferential position relative to potential competitors for "firm" gas sales.

Fallacious Rationales for Perpetuating System-Gas Sales Service

Pipelines and regulators still offer a number of rationalizations for preserving a regulated sales service. The chief of these rationalizations are (1) the need of "core" customers' (homes and businesses served by local distribution companies) for supply security; (2) the desire of some such customers to continue receiving a "bundled" (sales + delivery) service; (3) the desire for price stability; and (4) economies of scale and aggregation that can be achieved in a pipeline's system-supply portfolio. On examination, none of these rationales has substantive merit.

Provision of Bundled Service

It is true that many customers of the interstate pipeline companies (not to mention **their** customers) prefer to delegate the separate negotiations regarding primary gas acquisition, long distance transmission, and local delivery, to someone else, and to continue buying a bundled service at a delivered price. There is no reason, however, why regulated pipelines or utility companies should have an exclusive or preferential position in the provision of bundled service at delivered prices. **If transmission services are made available to all shippers on equal terms, producers and other marketers (including unregulated marketing affiliates of the pipelines) can compete on equal terms for "rebundled" gas purchases by local distribution companies or any other party seeking such supplies.**

Supply Security

It is also true that local distribution companies require a high degree of reliability of supply in purchases on behalf of core customers. But there is nothing about purchases from a pipeline company, purchases of gas on a bundled basis, or purchases subject to a regulatory "supply obligation" (as opposed to an ordinary commercial contract) which makes such purchases inherently more reliable than acquisition of gas and transport services a la carte in a competitive market.

Any marketer or end-user is capable of buying gas at the wellhead with the same degree of firmness as a pipeline's regulated system-supply portfolio; a direct supply commitment from a major producer is, rather, likely to be marginally **more** reliable than a pipeline's contractual resale commitment. Regulation indeed makes a supply commitment **weaker** than an unregulated contractual supply obligation. Unlike the courts, regulatory commissions seldom require companies under their jurisdiction to perform on a contractual obligation that turns out to be unprofitable, nor do they compel compensation for failure to perform.

Pipeline "system supply" is a more secure supply source today only because and to the extent that FERC allows the pipelines to deny the same degree of "firmness" to their contractual transportation customers that they provide for their regulated sales customers.

Price Stability

Perhaps there is a substantial demand for the kind of "price stability" historically offered by pipeline sales of system gas. It is not evident, however, that many pipeline customers are willing to pay **higher** prices for such stability, and even less evident that public policy should accommodate such a preference, by which demand is rendered less sensitive to current market conditions. The question is becoming moot, however, in any event. As pipelines negotiate new supply contracts and renegotiate their old ones, their average gas-acquisition costs are coming to fluctuate increasingly with the spot market, while FERC is permitting the pipelines to modify their purchased-gas-adjustment ("PGA") mechanisms so that resale prices track current movements of such first-sale prices.

Finally, every price smoothing or hedging mechanism that is now available to the pipelines with respect to their system-gas portfolios is also available to any other gas purchaser or reseller at a comparable or lower price. **To the extent a real demand exists for price stability, therefore, pipeline system-gas sales possess no inherent advantage in serving this demand.**

Economies of Scale and Diversity of Aggregation

It is also true that economies of scale and diversity exist in the acquisition and aggregation of natural gas for resale. But the optimum scale may well be larger or smaller, and the optimum scope more or less diverse with respect to climate or other load factors, than that of a given pipeline's system-gas portfolio. A competitive market will seek out and favor the most efficient scale and configuration of portfolio aggregation. **A regulatory preference for pipeline system supply simply creates a preference for a given scale without regard to its optimality, and protects the pipeline's marketing operation from competitors, even of the same scale, that might in fact aggregate more efficiently.**

What Is to Be Done?

The task to be accomplished is a simple one in concept, and though its detailed implementation will involve some complexity, it will be far simpler than the contortions the FERC is now imposing on the pipelines and their customers in its attempt to perpetuate and rehabilitate a traditional regulated sales service whose justification is past --- through rate "reform" and proceedings directed at crafting "gas inventory charges" ["GICs"] for example.

FERC's strategic error, beginning with its creation of special marketing programs ["SMPs"] in the early 1980s, through Orders No. 436 and 500, has been to authorize unbundled transportation of shipper-owned gas as new services, in addition to the traditional bundled and regulated sales service, with separate volume projections and cost-allocations, separate rate schedules, and distinct terms of service. The simpler, more expeditious, and more efficient course would have been (and still is) to split the existing sales service into (1) a single schedule of stand-alone transport services, rates, and service conditions that would apply to both customer-owned and pipeline-owned gas, and (2) a competitive marketing business, deregulated to the greatest degree permissible under the NGA and NGPA.

FERC should now require (and if FERC is unwilling or unable, Congress should mandate) the total separation --- functional, accounting, and organizational --- of the buying and selling of natural gas from its physical delivery. To the extent the pipeline companies remain marketers of natural gas --- and all or most of them will choose to remain so --- they should be required to carry on these functions in separate marketing affiliates that would deal at arms-length with their regulated transportation units. Whatever balancing rights or penalties applied to non-affiliates and whatever storage services were provided under transmission tariffs would be the same for affiliates as for non-affiliates --- in great contrast to the present situation.

Creating a Secondary Market in Transport Services

The Need for, and Inevitable Faults of, Cost-of-Service Rate Regulation

The justification for regulating gas pipelines has been and remains the classical concept of "natural monopoly". Unregulated entry into naturally monopolistic industries is expected to result in wasteful excess capacity, while the combination of restricted entry and unregulated rates is expected to encourage price discrimination and monopoly exploitation of consumers (and/or "monopsony" exploitation of producers).

Precisely where rate regulation is most justified, however --- where and when capacity is inadequate --- cost-of-service ratemaking fails to perform one of the most critical functions served by prices in unregulated markets --- the rationing of limited supply to its highest-valued uses. Allocation of price-constrained supplies of any good then has to be accomplished by some non-optimal and, indeed, non-economic mechanism or set of rules, such as "first-come-first-serve", lotteries, prorationing, or administratively-determined "priorities". Some such mechanisms are inevitable concomitants of cost-of-service rate regulation or any other ratemaking formula that fosters an apparent shortage or surplus of capacity by mandating prices that are not market-clearing prices. Inefficiencies and dislocations are particularly mischievous to the extent that demand is subject to seasonal and other, unpredictable fluctuations, as is the case in the gas industry.

The present combination of ratemaking and allocation rules for interstate pipelines is specially troublesome. It reduces effective delivery capacity at periods of peak demand and fails to allocate to its most valued uses that capacity which is made available, as parties with firm transport rights "hoard" or underutilize them, and that effective capacity is not allocated to its highest-value use. While some rate reforms under consideration by FERC --- seasonally differentiated rates, for example --- will reduce capacity misallocation, I know of one and only one fundamental corrective.

A Free Secondary Market in Transport Services ("Capacity Brokering")

The one simple innovation that can effectively mitigate these inefficiencies and, indeed, "clear the market" for regulated transport capacity, while allocating that capacity to its highest uses, **is a free secondary market in transport services.** Whatever non-economic basis is used for the **original allocation** of transportation rights, all that is necessary for an efficient **reallocation** is to permit the free (unregulated) subdivision (by volumes, season, priority of service, etc.), recombination, and purchase, sale, exchange, or assignment of such rights.

Participation of pipelines as regulated entities in the secondary market for capacity on their own or other pipeline systems would have to be restricted or regulated so as to prevent them from using "capacity brokering" (FERC's misnomer for the secondary market) as a device to enhance market power or evade cost-of-service revenue restrictions. Free trading of capacity entitlements among other parties, however, would assure that potential buyers and sellers alike would act on the true scarcity value (= "opportunity cost") of transport services, at both seasonal peaks and slack periods. Accurate scarcity (or surplus) prices would correctly signal the relative value of other peak-supply options, including existing or contemplated storage facilities, and contemplated new pipelines or capacity enhancements.

What Is to Be Done?

FERC has grasped --- albeit very dimly --- the uses and value of "capacity brokering" but has seemingly done everything in its power to limit its scope and indeed to discredit and provoke opposition to the very concept. What is required is not a complex auction system administered by FERC, or particularistic capacity-brokering "experiments" controlled by the "host" pipelines. There is certainly no need to extend FERC certification authority to otherwise non-jurisdictional pipeline **customers** desiring to "broker" transport rights in the secondary market.

In outline, all that FERC (or, at last resort, the Congress) must do is to order that every right or obligation pursuant to a FERC-approved transportation certificate, tariff, rate schedule, or service agreement, be divisible and assignable, in whole or in part, temporarily or permanently, without unreasonable restriction, and that any non-assignment terms in existing certificates, tariffs, rate schedules, or service agreements are henceforth unenforceable.

Such an order will require various follow-up actions by FERC in the areas of cost-allocation and rate design, for example. As far as I can anticipate, however, all such corollary moves will involve **simplifications** and rationalizations relative to the status quo of FERC regulation. A robust secondary market implies, for example, that provision of "interruptible" transport service will mainly be the function of primary or subsequent purchasers of firm transport rights, rather than the pipeline itself. This development will call for increasing the proportion of fixed costs allocated to fixed charges for firm pipeline service --- perhaps by resurrecting the classical (un-"modified") "fixed-variable" rate format. Such a change, however, would relieve the pipeline and FERC of the duty they now have, in setting rates, of speculating on the future split between "firm" and "interruptible" throughputs.

Certification of New Pipeline Capacity

The need for regulation of transportation charges is much weaker in today's mature gas industry than it was when the NGA was enacted. Most of North America's major gas-producing areas and load centers already have multiple competing pipeline connections, while the gas industry as a whole faces vigorous competition from many sources of energy. Some regulatory oversight must remain on transportation charges in the many less-than-fully competitive geographic markets, however, and to prevent the leveraging of market power over transportation into undue preference in sales markets.

The case for control over new pipeline construction and capacity additions is even weaker. The evils of overbuilding and "wasteful competition" that motivated the certification requirement in the NGA are nonexistent in a competitive industry, provided new capital costs are not imposed on captive customers or suppliers by regulation or contract. The only remaining justification for FERC's active exercise of its jurisdiction in this area is to provide a one-stop federal review of environmental impacts and requirements.

FERC is thus not an appropriate entity to decide what pipeline facilities should be built and by whom. Nor, I might add, is the California Public Utilities Commission. They lack the necessary information, insight, and incentives, and the ability to proceed with necessary dispatch or to arrive at sufficiently flexible outcomes.

Unfortunately, however, neither is the private sector now capable of making such decisions rationally. Investors also lack proper information and incentives, because of the misleading signals associated with regulated and inflexible transport rates, and the inflexible and preferential allocation of existing transport and storage capacity. These market distortions are now creating false readings of shortage and of the market value of specific additions to transmission capacity, much as the false signals generated by mixture of dedication, price regulation and deregulation in the early years of the NGPA, regarding the need for additional gas-producing capacity.

The first and most urgent task of the regulators today with respect to the need for new pipeline construction is, therefore, to complete the transition to flexible, competitive markets through measures such as I have suggested here.

Summary

I believe that the natural-gas industry is in excellent shape, and already properly organized to meet a major part of the nation's primary-energy demand well into the new Millennium. Flexible prices and market incentives will evoke the physical resources we need without any dramatic new government incentives. What is called for now is simply to complete the revolution in market structure that has been underway since passage of the NGPA in 1978. This means, first, cleaning up the biggest and clumsiest relic of the old regime --- the regulated sales services of the pipelines, and second, extending the same market flexibility that now exists in the production and sale of gas to its delivery, through free exchange of transportation services in a secondary market.

PROSPECTIVE ON WORLD ENERGY MARKETS:
REAL COSTS WILL CONTINUE TO FALL

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INTRODUCTION

The centuries-long trend of prices for useful energy has been ever downward, because technology has increased the known reserves of fossil hydrocarbons, reduced conversion and delivery costs, and improved end-use efficiencies faster than growing demand and diminishing returns from exploiting a fixed resource base could pull up primary-fuel costs. Despite an episode of unusually high prices in the late 1970s and early 1980s, energy markets are still on this long-term course. The real prices of oil, gas, and coal are not likely to show any sustained rise, either in this century or the next --- when they will be supplemented and replaced by cleaner, easier-to-use, and cheaper primary-energy resources. It is a tautology, and an uninteresting one, to assert that the finiteness of resources guarantees ever-rising marginal costs, because this inference has meaning only on the assumption of static technology. In a world of dynamic technology, resources are not finite. Instead, the real or perceived "threat" of shortages and higher prices for one fuel or fuel-using technology create economic niches for substitutes, and the incentives, pecuniary and otherwise, that make these substitutes available.

SUFFICIENCY OF OIL AND GAS RESOURCES

To see why emergence of a sustained upward price trend is not imminent, we need only consider the two leading fossil fuels --- petroleum and natural gas --- and only the present stock of proved and probable (or "indicated") reserves in identified reservoirs. With respect to these fuels, moreover, we need consider only those techniques for extracting, transporting, converting, and using them that are already proved and in service, embodied in durable goods that are available "off the shelf", and commercially viable at the range of end-user prices seen over the last three years.

Globally for both oil and gas, the volumes of proved and probable reserves in identified reservoirs are capable of supporting several decades of consumption at current rates; world reserve-to-production ratios are at or near to their respective all-time highs. In both cases, moreover, the bulk of the known inventory is contained in a couple of dozen deposits, from which long-term marginal production cost is at least an order of magnitude less than recent market prices, leaving a wide gap to close before the former could begin to determine the latter. The historical record to date shows no clear upward tendency in either costs or prices; in our judgment, those who assert that the onset of such a trend is now imminent bear the burden of explaining exactly why such a momentous and unprecedented change in direction must occur in this decade or the next, rather than beginning (say) five decades ago or five decades hence.

No one can seriously contest this picture of the aggregate oil-and-gas resource base on a world scale. Until the mid-1980s, nearly every prominent forecasting institution nevertheless predicted monotonically rising prices for marketed energy, driven by inexorably rising marginal costs within critical sectors of the world's fossil-fuel supply. In 1989, many of them are still projecting such a trend, only with a changed initial value and/or changed starting date. Such a price outlook is compatible with the overall resource picture only if one assumes that product differentiation and interregional transport-cost barriers *permanently* divide world energy markets into non-competing segments.

Those forecasting models that generate sustained rises in primary fuel prices, commencing immediately or within a decade or less, typically define their relevant product as either oil or natural gas, and treat supply, demand, and price data for the alternate fuel (and all other energy resources) as exogenous influences on the subject market. Analyses of the global market for crude oil assume a critical structural boundary separating Middle Eastern and/or OPEC oil production from all other production. Analyses of the long-term outlook for natural-gas markets are framed geographically to pair North American, European, or Japanese gas demand, taken in isolation, with its current and immediately prospective gas suppliers. North American gas-market analyses, for example, ignore natural-gas market conditions in other regions, and deal with the world oil price level only as an exogenous variable.

Such conceptual divisions do correspond to existing short-term distinctions between oil and gas with respect to market organization and price structure. Division of crude-oil production into a Middle Eastern and/or OPEC sector and a sector containing all other sources likewise mirrors those differences in the mix of technical supply characteristics and national institutions that have had a palpable effect on market behavior since the price upheavals of the early 1970s. And the treatment of North American and European natural-gas markets in isolation from each other simply reflects the current absence of a gas trade in either direction between the two continents. Such demarcations are therefore relevant in explaining events of the recent past, or predicting events in the near future. But this relevance endures only within a time frame short enough that one can safely disregard changes in the mix and location of capital assets. This fragmentation of fuel markets is sure mischief in any conceptual scheme intended as a guide to anticipating longer-term economic trends.

At any particular time, the boundaries between "relevant markets" for primary energy depend on the nature and location of the existing stock of durable goods put in place to serve those markets. To the extent that the analyst chooses a forecasting time-frame in which the stock of such assets is capable of changing, however, the boundaries between relevant product or geographic markets are also capable of shifting or disappearing. Most critically, the relevance of today's boundaries is sustainable only within a certain range of prices. Expectations of a world oil-price level above $20 or North American gas prices that approached or exceeded the equivalent of $20 oil would steer both the new investment required for the replacement of old capacity and the investment in new capacity intended to serve demand growth, in directions that directly threaten the existing boundaries between relevant markets.

HOW QUICKLY CAN INDUSTRIAL AND MARKET STRUCTURE CHANGE?

The time required for a market or industrial sector to change beyond recognition is surprisingly short even in a "painless" turnover of capital assets --- i.e., one that does not cause the scrapping of any capital goods before their otherwise expected retirement dates. A reasonable rule of thumb is that a typical class of producer durables has a "half-life" of ten years. Assume an average annual replacement rate that corresponds to this figure and a 3-percent annual rate of growth in demand for total capacity. Under these circumstances, a new primary resource, process, or final product whose superiority in cost and/or performance permitted it to capture all replacement demand and all growth in the market would account for half of total capacity in 8.5 years, two-thirds of the total in eleven years, and 85 percent within 20 years.

The fuels and energy sectors have seen one such technical revolution after another. Destruction of forests in Britain and the Northeastern U.S. in the early 1800s was a powerful stimulus to the permanent substitution of coal and coke for wood as the chief steam-transport fuel, and for charcoal in metallurgy. In the 1840s and 1850s, it was the near-extinction of the sperm whale for the production of lamp oil that created a market for kerosene --- a superior lighting fuel --- and with it the petroleum industry. Between about 1890 and 1910 electricity replaced manufactured gas as the dominant source of urban lighting throughout the then-"modern" world.

Beginning in the 1920s, the development of welded steel pipe allowed the high pressures required for long-distance movement of gas at acceptable costs. As quickly as pipelines could be laid, natural gas immediately replaced manufactured town gas for cooking and space-heating and, through the 1960s (i.e., until the appearance of regulation-induced "shortages") was capturing virtually the entire North American replacement and growth demand for stationary heat. In the 1950s and 1960s outside North America, however, the cheapness of oil was allowing it to replace coal as the principal industrial, electrical-generation, and spaceheating fuel. During these two decades, oil consumption increased 7 percent annually in Western Europe and 16 percent annually in Japan. As a group these instances suggest that we could dispense quickly and economically with oil, or any other primary fuel, if we really had to do so.

THE UNLIMITED POTENTIAL FOR SUBSTITUTION

The factor that unites markets for oil and gas in the long run is their nearly unlimited ability to substitute for each other in almost every application. There is no large-scale use of petroleum liquids --- or any other primary fuel --- that is not now actually being served by methane or a methane derivative at a comparable cost. The reverse is also true: just about anything gas --- or any other primary energy source --- can do, a petroleum product is now doing just about as well, also at a comparable cost. Compressed natural gas ("CNG") or liquid fuels derived from methane (methanol and synthetic gasolines) already substitute for petroleum distillates even as transport fuels --- in some cases at lower prices and with lower fixed costs and non-fuel operating expenses.

Thus, there is no foreseeable combination of rising world oil demand with stagnant or declining oil production outside the Middle East and/or OPEC, which will give Saudi Arabia, Iraq, or any other oil producer or group of producers, control over world energy prices --- if "control" means the ability to sustain those prices at levels exceeding the incremental cost of natural gas delivered into critical market areas, such as Western and Central Europe.

Fifty years or more of natural-gas infrastructure investments in North America, and fifteen years of such investment in Europe have already made it possible to transport gas from remote locations to major consuming centers at remarkably low levels of incremental cost. Within the capacity limits of the existing infrastructure, natural-gas suppliers are able to compete with petroleum products for all stationary-fuel uses at almost any price level. Much of the investment now embedded in the natural-gas industry occurred in an era of high-cost oil. Crude oil at $30 to $40 per barrel, for example, made it economic to construct a major pipeline from Siberia to Europe. Once such a pipeline was built, however, the cost of moving gas over that route fell to a fraction of its alternatives, and gas from the U.S.S.R. is now Europe's lowest-cost source of incremental energy.

According to the BP Statistical Review of World Energy, world natural-gas reserves were equivalent to 74 years of production at year-end 1987. Moreover, average annual reserve additions have been running at more than three to four times annual production. In addition, methane deposits are more widely dispersed than crude oil; there are natural-gas finds or indications in almost every country. These resources undermine and ultimately negate the power of Middle Eastern oil producers over world energy markets --- their capability in this respect is no different from that of an equivalent addition to the oil resources available outside the Middle East or OPEC.

The relevant product for long-term analysis thus includes both oil and gas. To the extent that a long-term forecasting model does specify supply, demand, and prices separately for the two primary fuels, therefore, the sets of market variables for the two fuels must receive equal and parallel treatment, and the mutual feedback links between sub-markets for the two commodity groups will be among the model's most critical components.

UNITY OF THE WORLD MARKET

The principle that creates a single world market for primary energy, even in the short term, is the cheapness of tanker transportation for crude oil. These costs are so low as a fraction of the current commodity value of oil that systematic differentials between oil prices at the Persian Gulf, the U.S. Gulf, Rotterdam, and Singapore, are barely (if at all) discernable over the daily fluctuations of spot prices.

Intercontinental trade in natural gas or methane derivatives as such does not yet exert a directly unifying influence on global energy markets as do the movements of crude oil and refined products. But even in the present configuration of markets, Eastern Hemisphere gas supply already constrains the price of natural gas in the United States and Canada --- through the medium of the world oil price, which is itself constrained by actual and potential competition from gas in Europe and Asia.

The emergence of a direct intercontinental gas-price link is not an unthinkable development, however. Oil-price expectations in the $20 range are adequate to support investment in supplying North America with methane or its derivatives from remote undeveloped sources --- including pipeline supplies from the North American Arctic and overseas gas transported as LNG, methanol, or synthetic gasoline.

However finely one chooses to disaggregate supply, demand, and markets in constructing a formal forecasting model, therefore, a simple mental paradigm that consists of a single fossil hydrocarbon and a unitary global market probably serves just as well in explaining the past course of energy prices, and for understanding why a rising price trend is not a likely feature of the foreseeable future.

NEW DISCOVERIES, TECHNICAL ADVANCES IN CONVENTIONAL FUEL SYSTEMS, AND NON-FOSSIL ALTERNATIVES

While competition between oil and gas produced from the present inventory of proved and indicated reserves, using existing technology, may be sufficient to delay indefinitely any sustained upward tendency in energy prices, additional forces are at work expanding supplies and pressing costs downward. Investment in new oil-and-gas reserves and new producing capacity will occur, whatever the current level of expected prices. Technical advance will continue and, we believe, accelerate within the existing fossil-based energy-supply chains. Taking into account the effects of recent progress in oil-and-gas exploration, production, and transport techniques, oil-price expectations below $20 per barrel may well prove sufficient to maintain steady growth in non-OPEC oil production outside the Middle East. And it should not be surprising if gas-price expectations lower than $2.50 per million btu (mmbtu) sufficed to maintain current levels of conventional gas reserves in the established producing areas of the United States and Canada.

Finally, today's menu of energy-supply options that are independent of the existing oil-and-gas delivery systems, and competitive in cost and acceptable with respect to environmental impact is already more diverse than ever before and is almost certain to grow in diversity at an increasing pace.

A ROLE FOR COAL OR NUCLEAR POWER?

We have skipped over the prospects for coal or nuclear fission, not only in the interest of simplifying our exposition, but for another, sufficient reason: While coal and nuclear energy (as we know it now) will not disappear overnight as sources of primary energy, new investment in these systems is not essential to stable or declining constant-dollar prices for useful energy. Existing coal- and nuclear-fueled facilities do cut deeply into otherwise expected oil demand, and the installed fuel-switching capacity of power stations and industrial fuel users is a moderating influence on oil-price fluctuations. It is at least conceivable, moreover, that new processes will permit coal to overcome environmental objections sufficiently to retain some long-term presence as a primary energy source, and to share with natural gas the job of capping oil prices. In view of the real and perceived environmental and safety problems associated with these resources, however, their future is at best cloudy.

Nuclear fission would be out of the running on economic grounds for serving replacement or incremental energy demand, even if its unique safety concerns were to be resolved. The nuclear fuel cycle is too complex; nuclear power stations are too capital intensive (resulting in unit costs that increase steeply when a plant can not be or is not operated at close to its design capacity); and the optimum scale of plant is too large (precluding cogeneration applications). Scale thus combines with capital intensivity to make the minimum unit of investment stupendously costly. The time required to design, build, and test such facilities is too long, and once commissioned, they are unreliable.

Combustion turbines and their combined-cycle variants are superior to state-of-the-art nuclear plants by a wide margin in every one of these dimensions. Capital costs per kilowatt are only ten to twenty percent of nuclear-plant costs. The optimum scale of generating unit in terms of kilowatts of installed capacity is about an order of magnitude less for combustion turbines than for coal- or nuclear-steam turbines. The combined effect is to permit addition of gas-turbine capacity in units that cost tens of millions rather than billions of dollars.

The conversion efficiencies of new combined-cycle turbines are higher than for any other thermal-generation mode, and their noxious emissions per produced kilowatt are lower than for any other any generation technique based on combustion of fossil fuels. So long as natural-gas prices remain in the range of $1.50-$3 per mmbtu, total costs per kilowatt-hour will be about half of the hoped-for cost of power from new nuclear-power stations (even at high load factors where comparisons are most favorable to the nuclear option). In the face of such competition, nuclear construction programs cling to life only on the basis of political rationales --- some of which are at least as outdated as the economic analyses that once seemed to support nuclear power.

THE INEVITABILITY OF LOWER COSTS

During the 1970s analysts and decision-makers came to assume, with little apparent reflection, that the cost of producer durables, particularly facilities for the energy industries, would inevitably increase with the passage of time. As with several other axioms that drove investment behavior and public policy during that period, the truth is quite the opposite by a wide margin. The best rule, indicated by common sense and confirmed in the historical record, is to assume that the unit cost of producing any given thing or conducting any given activity will go down, unless there are specific and exceptional reasons to expect otherwise.

There is utterly no reason to suppose that the costs of producer durables for the energy industries are exempt, as a class, from this rule. There are obvious exceptions, but the downward slope of oil-and-gas-industry input costs, as adjusted for performance, is strong and clear. Curiously, however, we have yet to encounter a long-term oil or gas supply projection or model that explicitly or implicitly incorporates the expectation of falling input costs.

Consider well-drilling costs: Over the last 25 years, myriad improvements in drilling bits, muds, lubricants, motors, and the like, have caused the constant-dollar cost of drilling and completing a well of standard depth and diameter in a given environment to decline by about 5 percent per year. On the geographical and technical frontiers of the industry, where the bulk of new capacity is typically added, input costs tend to fall even faster. A development well at Prudhoe Bay on Alaska's North Slope, for example, now costs only about about one-third as much (in nominal dollars!) as did a comparable well in 1977.

Some activities have been changing so radically in character that it is difficult to define, much less measure, the cost per unit of input. Increases in computer power and program sophistication have been driving a permanent revolution in oil-and-gas exploration strategy and technique that is making the exploration dry hole a threatened species in some exploration provinces. Three-dimensional reservoir mapping assures both a significant improvement in average production rates for new development wells and a quantum increase in the total recoverable hydrocarbons from a given structure.

The most dramatic single technical breakthrough of recent years, however, is horizontal drilling, whose fruits will include higher production rates per well, greater ultimate recovery of the original "in-place" oil and gas, lower unit costs of production and, as a combined result of all the foregoing, an expansion in the number and kinds of hydrocarbon-bearing structures that will be deemed "commercial." In our judgment, horizontal drilling is an innovation whose significance will rank in petroleum-industry history with invention of the rotary drill, catalytic cracking, and geophysical exploration.

Falling costs and improved performance are not confined to the primary-extraction sectors of industry. Estimated construction costs per unit of throughput capacity for the most recent proposals for pipelines and LNG systems to serve natural-gas reserves in the U.S. and Canadian Arctic are one-half to one-third those of their 1970s predecessors. Similar trends are evident in the expected capital costs per unit of throughput for elements of the LNG, methane-to-methanol, and methane-to-gasoline systems that will permit marketing of natural gas from remote sources. We have already alluded to the recent transformation of combustion turbines and combined-cycle plants based on them from high-cost and temperamental sources of intermittent electrical power, into a clear first-choice position among electrical-generating alternatives.

HOW THE NEW "ALTERNATIVE ENERGY" DIFFERS FROM THE FAILED VENTURES OF THE 1970s: FEWER MOVING PARTS

Finally, the most exciting applications of new technology are bound to include new energy sources that will not be based on the combustion of fossil fuels, new means of converting one form of energy to another, and new, more efficient end-use devices. An unprecedented number of such revolutionary advances in the production, delivery, and use of energy are on the threshold of breakthrough to scientific credibility or commercial feasibility. Only a small fraction of these will prove viable, but the number, variety, and potential impact of candidate technologies are so great that one or more such innovation can hardly help but have an early effect on industrial and market structure and prices.

Generally, the innovations of the new era tend to embody quantum increases in efficiency. As a direct concomitant of greater efficiency, moreover, they will embody quantum reductions in discharges of environmentally burdensome waste materials and heat. In these respects, the front-running candidates for such a role differ dramatically from the massive government-sponsored research, development, and demonstration ventures in "alternative energy" sources during the 1970s.

The technologies and hardware selected for commercialization at that time mostly involved increases in the scale and complexity of established technology --- a bias that meant higher capital costs, larger financial risks, reduced operational efficiency, and reduced reliability. For this and related reasons, advanced coal-combustion systems, synthetic natural gas, the mining and retorting of shale oil or oil sands, and fast breeder nuclear reactors offered little or no relief from the environmental and safety problems connected with existing oil- or coal-fired energy systems. Similarly, the measures adopted or proposed during the 1970s for mitigating environmental damage from both old and new energy technologies tended to center on add-on devices or processes, which would further increase capital costs, further degrade reliability and efficiency, and add to solid-waste disposal problems. The characteristic response of government and big business to reliability and safety concerns had the same biases: they centered on overbuilding and redundancy, whose nearly inevitable result was to increase both short- and long-term incremental costs.

The innovations in extraction, transmission, and conversion of energy that herald the Third Millennium promise, as a class, to be very different. Based upon recent advances in the understanding of fundamental physical processes, they tend to involve or permit significant reductions in scale and complexity compared with homologous elements in the present system. On the whole and for the same reasons they are likely to be cleaner, safer, and more reliable.

Photovoltaic solar energy is one cluster of such technologies that has already passed the experimental stage, but whose breakthrough to commercial status occurred without any dramatic announcement. In the late 1970s, this power source was economically attractive only for the most minute and/or remote applications: spacecraft, isolated meteorological and radio-relay installations, timepieces, and novelties. In the late 1980s, however, solar cells make up a competitive energy source for lighting and appliance operation in rural homes; the biggest commercial market thus far is for such uses on recreational boats and vehicles.

The cost of solar cells per peak watt has fallen by about an order of magnitude over the last decade and promises to continue falling. Concurrent improvements in transistors and other electronic components are causing appliance manufacturers to shift to low-voltage direct current (DC) for a growing number of household and business applications. Such appliances are generally more energy-efficient than their 110- or 220-volt alternating-current (AC) counterparts, and are thus equipped with a converter when they depend for power on the AC utility line. The availability of such appliances has another consequence, however: Taking into account the superior end-use efficiencies of low-voltage DC, solar power is becoming economically competitive for lighting and refrigeration — indeed for every household energy use except spaceheating and cooling. Thus, in some climates entire homes can be equipped to operate on solar electricity at a total cost in the same range as that of power delivered by utilities.

NON-FOSSIL ALTERNATIVES

Solar electric power is just one of many new devices, processes, or clusters of technology that might lead to early enhancements in energy supply, reduce supply costs, and/or reduce real or perceived environmental damage. As we write this paper (May 1989), the odds appear not to favor "cold fusion" (as described earlier in the year by a group of Utah chemists) as being the basis for such a critical technical breakthrough. But if those finite odds, however small, are added to the greater or lesser probabilities that correspond to each of dozens of other "maybes" — doubtless including some that you and I are not even aware of — the cumulative expectation is very great that at least one will be of truly revolutionary impact, and that many others will have a perceptible downward influence on costs.

Superconducting materials and their applications clearly deserve more than one entry in such an inventory of candidates. A long-overdue item is some electricity-storage device that will smaller, lighter, and/or cheaper per unit of capacity than the lead-acid battery (which was the first among such devices, and which has now dominated the field for a century and a half). This particular innovation could level peak-period generation and/or transmission costs toward base-load values, and powerfully enhance the economics of intermittent power sources such as solar, wind, and tidal energy. Its appearance could also be the critical event permitting electricity to replace gasoline as power for motor transport.

It is also a good bet that at least one commercially viable device will soon appear for producing electricity by some chemical process analogous to combustion, but which dispenses with mechanical intervention in the form of turbines, pistons, or the like. Even if such a "fuel cell" were based on oxidation of a fossil fuel (most likely methane or a natural-gas derivative), its conversion efficiency would certainly be much higher, and harmful discharges per unit of final product less (by an even greater proportion), than with current thermal generation methods.

The reader's list will surely differ from ours, and will surely attach different probabilities to specific entries. It would, however, take a vastly shorter list, and/or considerably greater pessimism about the odds on specific items, to conclude that new, lower-cost, and cleaner systems for delivering useful energy are not likely to dominate incremental and replacement capacity over the next twenty-five years. If such a shift does indeed fail to occur, moreover, we wager that the reason will not be the lack of suitable non-fossil technologies, but rather, improved performance and reduced costs associated with the supply of useful energy from conventional sources — principally oil and natural gas.

INNOVATION WILL ACCELERATE

There are many forces working together to accelerate the pace of scientific and technical advance, and these forces will themselves gain immensely in power over the next decade or two. One potent influence is the quickening internationalization of science, technology, business, and the culture of the world's elites. It is not a great exaggeration to say that everybody in the world is now potentially accessible to anyone else, and potentially exposed to everybody else's knowledge, views, tastes, and perspectives. The two goods that increasingly dominate international trade are information and financial capital, moreover, which unlike traditional commodities are indifferent to national boundaries, and whose "transport" costs are only a trivial fraction of their value.

The potential for universal, instantaneous communication combines with computerization to increase by several orders of magnitude the effective supply of services traditionally performed by all sorts of engineers, designers, appraisers, analysts, forecasters, and scientists. The wide variety and availability of applications software utterly changes the distribution of intellectual power within society — the one kind of power that will henceforth matter most in human affairs. Millions of individuals, singly or in informal or organized groups, now command intellectual capabilities that are more sophisticated and more powerful, and access to information resources that are wider and deeper, than any person or institution on earth (including Exxon or Chase Bank, MIT or Brookings, Bechtel or the Corps of Engineers, the IRS or SEC, or the CIA or KGB) could command only twenty years ago.

Another development favoring the acceleration of scientific and technical change is the increase since World War II in the number of national economies in the first rank with respect to per-capita income and product, and technical and organizational sophistication. Once a nation reaches that position, its further economic advance is no longer possible simply by "industrialization" — increasing the crude ratio of capital to labor while "borrowing" productive and organizational methods from a handful of more advanced nations. Each front-runner acquires a set of needs, incentives, and abilities, comparable to its erstwhile "forerunners", to make a proportional contribution to the overall productive prowess of humanity.

The sharing of this effort among different cultures and within institutions having different incentive structures imparts still further momentum to the innovative process, because it multiplies the number of perspectives from which mankind is likely to approach a given problem of technique or organization. Some kinds of inventions and innovations will surely be best nurtured where values and institutions encourage individual initiative and reward individual achievement; others will tend to emerge where the emphasis is on teamwork, consensus, and group pride. The novelty whose invention springs from one social context, moreover, may find that another is more congenial to its practical implementation, while its greatest consumer or social benefits may be captured by members of still other cultural groups.

The ultimate guarantor that technical advance will quicken is the recent worldwide discovery (and re-discovery) of market mechanisms as the premier resource-allocator, and of political freedom as the most effective framework in which to motivate human imagination and effort. These discoveries are showing their most dramatic forms in Communist countries as a total upheaval of values and social institutions that is packing into 1989 alone all of the unfulfilled promises of 1776, 1789, and 1848. Concurrently, however, re-discovery of the market is manifesting itself in the capitalist West and Third World countries through movements for privatization, unbundling, de-averaging, or deregulation of various economic activities. A common theme in the many national variants of the World Revolution which closes the Second Millenium is the injection of optimizing behavior and rewards for innovation into virtually every level and kind of human activity.

SUMMARY

Energy is, after all, a resource of unlimited abundance, and is available for human use in an unlimited number of forms. There is no inherent social need for oil, gas, coal, or any one primary energy source. We seek instead ways of supplying light, heat, motive power, and the small hydrocarbon molecules that are the handiest building blocks for making organic chemicals. Our menu of options for serving these needs is already vast, and we will choose one primary fuel or delivery system from this menu only for those applications, and only where and when it is the cheapest (or most effective at a given price). For so long as progressive market economies have coexisted with cultures that encouraged scientific inquiry and permitted economic rewards to innovation, mankind's menu of options has expanded and the choices it preferred on that menu have continually shifted.

Depletion of finite resource stocks and the full exploitation of renewable resource stocks on a local or regional level have played the triggering role for some historical shifts in primary energy supplies. Examples cited earlier included destruction of the forests of the North Atlantic rim and extermination of the sperm whale. Equally significant innovations in energy production and use, such as electric lighting, were adopted because of their own superiority in cost or performance without any visible impetus from scarcity-driven price increases. The net impact in both cases was similar, however: a better product at a lower cost. So it is today, and so it will be into the New Millenium.

Senator **Bingaman**. Thank you very much.

Next we will hear from Mr. Danny Conklin, who is chairman of the board of the Independent Petroleum Association of America.

STATEMENT OF DANNY CONKLIN, CHAIRMAN, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

Mr. **Conklin**. Thank you.

I brought with me from Amarillo a little cold, so you will have to excuse my deep-based voice.

But I want to thank you and the committee for the interest that you have shown in the natural gas business, and especially the concerns that you have shown in regard to the independent natural gas producers.

But I believe it is clear that domestic gas supplies are adequate to meet the immediate needs of American consumers. The problems in the natural gas industry today are primarily related to slack demand and regulatory inefficiencies, which reduce the ability of the natural gas producers to compete effectively for markets.

The question before us today is how to promote regulatory changes on both the federal and state levels, which will create a more competitive environment for natural gas.

However, I want to point out that I am very troubled by low gas prices at the wellhead, resulting in depressed drilling rates and the likely adverse impacts on deliverability of supplies these factors will cause in just a few short years.

We hear a lot these days about natural gas being the fuel of the future. As a natural gas producer, I am excited at this prospect. As a realist, I must warn the committee that we will not be able to meet these new demands at today's drilling rates.

And as a businessman, I know that we cannot increase that drilling rate without significant positive changes in current financial incentives.

First and foremost, we need higher prices. And higher prices are the best and quickest way to increase the producer drilling budgets.

Unfortunately, petroleum pricing remains unstable. And I think you should know that without higher prices, we may not be able to sustain the high enough drilling rates to do the job.

Now let us move to the question of how to create a more competitive environment for natural gas in the future. The Independent Petroleum Association of America does not believe that the Federal Government should mandate the use of one fuel over another. We believe that free and open markets, which promote and take advantage of competitive forces, provide the best guarantee that appropriate fuel choices will be made.

For natural gas to become the fuel of the future, producers must be able to get the gas from the field to the market without sacrificing excessive economic value in the process. Slack market conditions, combined with unreasonably high natural gas transportation rates on interstate pipelines, result in current netback prices at the wellhead, which are far below the replacement cost of gas.

Another problem facing the natural gas industry is the lack of pipeline capacity in the areas of the country where demand exceeds supply. The expanding gas markets in California and in the northeastern United States are examples of this phenomenon. Both markets could be well served by domestic natural gas, but are currently looking to imported supplies to meet a substantial portion of their growing demand.

We believe that this is at least partly because of the problem of capacity constraints on domestic pipelines and pipeline rate designs, which discourage both pipeline construction and maximum efficient use of pipeline capacity.

Congress and the American people must also realize that the economic, political and technological conditions necessary for successful natural gas development are the same as for crude oil.

For instance, any actions aimed at restricting crude oil operations, such as limitation on offshore drilling and on development of resources on federal lands on shore will have a negative impact on natural gas activity as well. It is important to keep this in mind as national energy policy takes shape.

Perhaps the greatest single problem facing producers today is our inability to attract the outside capital needed to fund the extensive drilling required to produce our vast domestic natural gas resources.

Congress can best help alleviate this problem through appropriate changes in tax legislation promoting the use of natural gas where necessary to protect the environment, and encourage, by whatever means necessary, regulatory changes, which will make it easier and more economical for producers to meet the needs of our markets.

Thank you very much for allowing us to testify.

[The prepared statement of Mr. Conklin follows:]

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

STATEMENT OF
DANNY CONKLIN
Representing the
THE INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA
AND

AMERICAN ASSOCIATION OF PETROLEUM LANDMEN
ASSOCIATION OF OILWELL SERVICING CONTRACTORS
CALIFORNIA INDEPENDENT PETROLEUM ASSOCIATION
COASTAL OIL AND GAS ASSOCIATION
EAST TEXAS PRODUCERS AND ROYALTY OWNERS ASSOCIATION
EASTERN KANSAS OIL AND GAS ASSOCIATION, INC.
ENERGY CONSUMERS AND PRODUCERS ASSOCIATION
FLORIDA INDEPENDENT PETROLEUM PRODUCERS ASSOCIATION, INC.
GEORGIA OIL AND GAS ASSOCIATION
ILLINOIS OIL AND GAS ASSOCIATION
INDEPENDENT OIL AND GAS ASSOCIATION OF NEW YORK
INDEPENDENT OIL AND GAS ASSOCIATION OF WEST VIRGINIA
INDEPENDENT OIL PRODUCERS' AGENCY
INDEPENDENT OIL PRODUCERS ASSOCIATION TRI-STATE, INC.
INDEPENDENT PETROLEUM ASSOCIATION OF MOUNTAIN STATES
INDEPENDENT PETROLEUM ASSOCIATION OF NEW MEXICO
INDIANA OIL AND GAS ASSOCIATION
INTERNATIONAL ASSOCIATION OF DESK AND DERRICK CLUBS
INTERNATIONAL ASSOCIATION OF GEOPHYSICAL CONTRACTORS
KANSAS INDEPENDENT OIL AND GAS ASSOCIATION
KENTUCKY OIL AND GAS ASSOCIATION
LIAISON COMMITTEE OF COOPERATING OIL AND GAS ASSOCIATIONS
LOUISIANA ASSOCIATION OF INDEPENDENT PRODUCERS AND ROYALTY OWNERS
LOUISIANA LANDOWNERS ASSOCIATION, INC.
MICHIGAN OIL AND GAS ASSOCIATION
NATIONAL STRIPPER WELL ASSOCIATION
NEW MEXICO OIL AND GAS ASSOCIATION
NEW YORK STATE OIL PRODUCERS ASSOCIATION
NORTH TEXAS OIL AND GAS ASSOCIATION
OHIO OIL AND GAS ASSOCIATION
OHIO PETROLEUM PRODUCERS ASSOCIATION
OIL INVESTMENT INSTITUTE
OKLAHOMA INDEPENDENT PETROLEUM ASSOCIATION
ORANGE COUNTY PETROLEUM ASSOCIATION
PANHANDLE PRODUCERS AND ROYALTY OWNERS ASSOCIATION
PENNSYLVANIA GRADE CRUDE OIL ASSOCIATION
PENNSYLVANIA NATURAL GAS ASSOCIATES
PENNSYLVANIA OIL AND GAS ASSOCIATION
PERMIAN BASIN PETROLEUM ASSOCIATION
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ROCKY MOUNTAIN OIL AND GAS ASSOCIATION
ROYALTY OWNERS AND INDEPENDENT OIL AND GAS PRODUCERS ASSOCIATION OF ARKANSAS
TENNESSEE OIL AND GAS ASSOCIATION
TEXAS INDEPENDENT PRODUCERS & ROYALTY OWNERS ASSOCIATION
VIRGINIA OIL AND GAS ASSOCIATION
WEST CENTRAL TEXAS OIL AND GAS ASSOCIATION

Before the Subcommittee on Mineral Resources Development
and Production of the Senate Committee
on Energy and Natural Resources
September 26, 1989

Representing America's Domestic Petroleum Explorer/Producers
For information call (202) 857-4722

Statement of the Independent Petroleum Association of America
before the
Subcommittee on Mineral Resources Development and Production
of the Senate Committee on Energy and Natural Resources
September 26, 1989

I am Danny Conklin, a partner in Philcon Development, an oil and natural gas exploration company in Amarillo, Texas. I am here today as Chairman of the Independent Petroleum Association of America, the national association representing the nearly 10,000 independent crude oil and natural gas explorer/producers who operate in all 33 states with oil and natural gas production. Independents produce 60 percent of domestic natural gas.

Mr. Chairman, I believe it is clear that domestic gas supplies are adequate to meet the present needs of American consumers. Indeed it is our belief that, while the short-term problems in the natural gas industry today are primarily related to slack demand, more serious long-term problems are caused by regulatory inefficiencies which reduce the ability of natural gas producers to compete effectively for markets. So the main question before us today is how to promote regulatory changes on both the federal and state levels which will create a more competitive environment for natural gas.

But before I go into our position with respect to regulatory inefficiencies, I want to point out that I am very troubled by low gas prices at the wellhead, resulting depressed drilling rates, and the likely adverse impacts on deliverable supplies that these factors will cause in just a few short years.

We hear a lot these days about natural gas being the "fuel of the future." As a natural gas producer, I am excited at this prospect. As a realist I must warn the committee, we will not be able to meet these new demands at today's drilling rate. As a businessman I know that we can't increase that drilling rate without significant positive changes in current financial incentives. First and foremost, we need higher prices. Higher prices are the best and quickest way to increase producer drilling budgets. Unfortunately, petroleum pricing remains out of our control and I think you should know that without higher prices we may not be able to sustain high enough drilling rates to do the job.

Now let us move to the question of how to create a more competitive environment for natural gas in the future. The Independent Petroleum Association of America does not believe that the federal government should mandate the use of one fuel over another. We believe that free and open markets which promote and take advantage of competitive forces provide the best guarantee that appropriate fuel choices will be made.

For natural gas to become the "fuel of the future", producers must be able to get the gas from the field to the market without sacrificing excessive economic value in the process. Slack market conditions combined with unreasonably high natural gas transportation rates on interstate pipelines result in current netback prices at the wellhead which are far below the replacement cost of gas. We urge Congress to use its persuasive abilities and legislative powers, where appropriate, to assure that the pipeline transportation rate making policies of the

Federal Energy Regulatory Commission encourage increased use of natural gas by making it more competitive at the burnertip.

Another problem facing the natural gas industry is the lack of pipeline capacity in areas of the country where demand exceeds supply. The expanding gas markets in California and in the Northeastern United States are examples of this phenomenon. Both markets could be well served by domestic natural gas, but are currently looking to imported supplies to meet a substantial portion of their growing demand. We believe that this is at least partly because of the problem of capacity constraints on domestic pipelines and pipeline rate designs which discourage both pipeline construction and maximum efficient use of pipeline capacity.

In this vein, it is important to recognize that, unlike interstate pipelines and local distribution companies which have their legal and regulatory fees subsidized by rate payers, small producers do not have this luxury. Pipelines and local distribution companies often join together to settle regulatory disputes without much consideration of the effect that their agreements will have on small producers. This is a problem because it is extremely burdensome for small producers to maintain adequate representation in prolonged legal and regulatory proceedings. I say this to emphasize how important it is to America's energy security for the regulatory agencies to take into account the effect of their actions on small producers so we can spend more time and money searching for oil and natural gas and less time fighting the regulators.

Congress and the American people must also realize that the economic, political, and technological conditions necessary for successful natural gas development are the same as for crude oil. For instance, any actions aimed at restricting crude oil operations, such as limitations on offshore drilling and on development of resources on federal lands onshore, will have a negative impact on natural gas activity as well. It is important to keep this in mind as national energy policy takes shape.

Perhaps the greatest single problem facing producers today is our inability to attract the outside capital needed to fund the extensive drilling which will be required to produce our vast domestic natural gas resources. This threat to the future of the natural gas industry is related to the problems of slack demand and regulatory inefficiencies. The best way that the Congress can help alleviate this problem is to make appropriate changes in tax legislation, promote the use of natural gas where necessary to protect the environment, and encourage by whatever means necessary regulatory changes which will make it easier and more economical for producers to meet the needs of our markets.

Thank you for this opportunity to be heard and please let us know how we can be of any further help in your consideration of this important subject.

Senator **Bingaman**. Thank you very much.

Next, Mr. Nicholas Bush, who is the President of the Natural Gas Supply Association.

We are pleased to have you here.

STATEMENT OF NICHOLAS J. BUSH, PRESIDENT, NATURAL GAS SUPPLY ASSOCIATION

Mr. **Bush**. Thank you, Mr. Chairman.

Good afternoon, I am Nicholas J. Bush and I am the President of NGSA. NGSA is an organization that represents domestic producers who market about 90 percent of the natural gas in the United States.

And with the understanding, Mr. Chairman, that my entire remarks will be filed as part of the record, along with the attachments, I would just like to chat for five minutes with you about some of the points that have been raised.

Senator **Bingaman**. That will be fine. Everyone's written statement will be made a part of the record.

Mr. **Bush**. We have attached two studies, Mr. Chairman, to our testimony that basically conclude, one, that there is a large significant natural gas potential resource base in the United States that will be utilized if the proper energy policies are pursued; and, two, we have attached to our statement, for the first time, a production capacity study that we have just recently finalized, that took a framed picture of December 1988 dry gas production for about 47 percent of the natural gas production at that time that existed.

The conclusion of the production capacity study is that there are going to be adequate supplies, as you have heard, for reasonably anticipated winter demand this year.

But I would like to make two or three comments about things that have been said today, and refer to specific policies, where the Congress, in particular, can do something.

And it does not have to do with arcane regulations, but real policy issues that are in front of you. That truly will be a tragedy if we have this current very good opportunity to utilize an environmentally beneficent fuel, such as natural gas, and we have deregulated the price now of natural gas, and we, of course, were major supporters of that and felt that it was the right thing to do.

At the same time, however, the Congress is considering moratoria on offshore and other prime resource development areas that cover federal lands, which hold 35 percent of the remaining conventional natural gas resources in the United States.

Now, it is going to be the ultimate irony if the Congress and all of us talk about all the benefits and all the potential of natural gas and, on the other hand, we deny the access for responsible and reasonable energy development in the areas that may be the most prolific.

So I would call that to your attention and the attentions of your colleagues here in the Senate, that, in truth, we find it to be a real non sequitur, often, to listen to environmental groups talk about the wonders natural gas and at the same time come in and urge the Congress to prohibit development in some of the most prolific areas.

And that is a very serious concern for producers, who have to have access to the lands if they are going to supply this gas at all.

That is the one thing.

The second thing I would like to talk a little bit about is yes, we have a deliverability surplus right now, but, as Mr. Conklin said, the concern with the producing community ultimately is how we might make a meaningful transition from the current deliverability surplus to a balanced, long-term supply-demand situation where we are in balance?

The key, from our standpoint, is the pricing mechanism that will be used by the natural gas industry in the future to secure long-term sales.

I think the thing that we have really centered on, and I want to clarify exactly what is in my statement so you have some understanding, Mr. Chairman, of what we are talking about here, the industry has gone through a significant transition in the last three or four years, in which traditional methods to buy and sell long-term gas have been eroded significantly.

We no longer have minimum bill processes. We no longer have the take-or-pay clause for all in effect, because of the debilitating effect of abrogation and the debate that has occurred over liabilities over the last couple of years.

So this industry, collectively, is trying to come to grips with how does a customer and a producer send signals back to one another in which producers can say here is how much we need to make the investments necessary to secure long-term supplies; and the customer can say well, here is how much I am willing to pay in order to secure those kinds of supplies.

There are many proposals in the industry being discussed. There are market basket prices, early marketing out, mutual market outs and contracts.

In my testimony I cite one, because I know it is of concern to you and others on this committee and others in the Senate and in the Congress. The gas inventory charge that has been proposed by the FERC, not the particular one, not the commodity, the spot—you know, not that dispute, just the fact that a gas inventory charge of some permanent duration be implemented in the industry; it is very important.

It is very important for us to restore some mechanism, contractually, so producers and customers can secure long-term supply. Some people, certainly Mr. Conklin in the IPAA and some other people, have some concerns with various aspects of the mechanisms of how some of these are done.

Senator Domenici and yourself and Senator Nickles have expressed some of those concerns.

But the mechanics of it are less important than the entity that says the settlement process ought to work to permanent gas inventory charges in which we have this mechanism, and it is very important that we put that in, we think, for the long-term acquisition of sales, that be restored.

Those are the points, Mr. Chairman, that I wanted to raise. And if I could raise one other point. Along with the environmental aspects of the production capacity, I would venture to say that the biggest problem we have right now in trying to get pipelines built is environmental clearances, of trying to get them through.

We have wetlands legislation that is going to have a major impact on potential pipeline construction. These are issues that are real issues that Congress does not have to create a national energy strategy, and it does not have to get into a major conflict.

If it could work on these very rifle-shot, key policy issues: How are we going to access this gas? How are we going to expedite the transmission of the gas? And how are we going to ensure that we have a long-term market for that gas?

And if we can do those things, we will complement the fine actions taken on the Fuel Use Act repeal and the deregulation bill.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Bush follows:]

TESTIMONY

OF

NICHOLAS J. BUSH

PRESIDENT

NATURAL GAS SUPPLY ASSOCIATION

BEFORE THE

SUBCOMMITTEE ON MINERAL RESOURCES,

DEVELOPMENT AND PRODUCTION

OF THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

Tuesday, September 26, 1989

Good afternoon, Mr. Chairman. I am Nicholas J. Bush and I am president of the Natural Gas Supply Association (NGSA.) NGSA is a trade organization of domestic producers who market about 90 percent of the nation's natural gas. We appreciate the opportunity to participate in this discussion of natural gas supply and deliverability issues.

Attached to my testimony for filing as part of the record of this hearing are two reports: one is entitled, Natural Gas: A Strategic Resource For The Future; a second is, An NGSA Member Company Survey: Natural Gas Sales and Productive Capacity As Of January 1, 1989.

The first study which was issued late last year is an assessment of domestic natural gas reserves. Several NGSA member companies participated in this study, as did a number of interstate pipeline companies and distribution companies. The document concludes -- as do most government and private sector analyses -- that the United States has significant potential natural gas reserves that will be developed if the proper energy policies are pursued.

Mr. Chairman, this Congress took a major positive step toward ensuring that the nation's natural gas potential will be utilized when it passed legislation leading to the total deregulation of natural gas at the wellhead. Unfortunately, however, Congress is also giving serious consideration to moratoria on the leasing of some of the nation's most promising resource areas. It will be unfortunate indeed if future domestic natural gas supply development is blunted because access to vital offshore areas for responsible exploration and development is denied. NGSA, the American Gas Association and the Interstate Gas Association of America are so concerned with the potential impact of these proposed leasing moratoria that we recently sent a joint letter expressing our opposition to such prohibitions to The President's Outer Continental Shelf Leasing and Development Task Force. A copy of the letter is attached.

Attached to our testimony also is a survey of natural gas sales and productive capacity as of January 1, 1989 that NGSA recently finalized. It is important to preface remarks about the results of the survey with some explanatory and cautionary words. First, the NGSA member companies that chose to participate in the survey represented 47 percent of December 1988 dry gas production -- clearly not the universe of domestic gas output. The data generated by the survey should not be "grossed up" or otherwise extrapolated to attempt to provide a definitive picture of the entire industry. This is simply our best view of sales and productive capacity at a particular time for a large segment of the domestic industry.

The survey does indicate that current domestic wellhead gas productive capacity should be sufficient to meet reasonably expected levels of demand, especially for the coming winter months. Clearly, the natural gas deliverability surplus is declining -- in particular in the Onshore Gulf region. And with the decline in domestic drilling in recent years, the so-called "bubble" of surplus gas deliverability is likely to be gone soon. But there is no indication that natural gas shortage at the wellhead is imminent. On the contrary, there is every indication that short-term wellhead supplies will be good.

One point, however, that I wish to raise with the Subcommittee, Mr. Chairman, is that the usual attention on gas supplies at this time of year focuses on deliverability at the wellhead. This is clearly too narrow a view. The critical issue is deliverability at the burner tip. While short-term operational limitations may be encountered by producers in extremely cold periods in some producing fields, there are adequate gas supplies at the wellhead to meet normal winter demand. But during peak winter demand periods when pipeline capacity in key areas is often full, the question of whether there will be adequate supplies of gas for many consumers may depend more on whether sufficient natural gas has been stored by utilities in heavy consumption areas; or, whether owners of unused storage have been willing to make it available at competitive rates; or, whether interstate pipelines have been and are pursuing open access and rate policies that allow competitively priced gas to reach markets.

We are encouraged by AGA's forecast for winter gas availability at the burner tip and by the seeming determination of all segments of the industry to do everything possible to avoid serious supply interruptions. Of course some brief, localized regional market disruptions during peak demand periods may occur -- there have been such events in recent years in Texas and California, for example -- but such occurrences will be resolved by the industry working with its customers. Should these isolated disruptions take place, however, they should not be viewed as indicative of a domestic shortage of natural gas.

Mr. Chairman, the most important question is whether the current adequate supplies of natural gas will become a long-term situation of supply and demand balance. We believe it can. It will depend, however, on many things. Producers cannot continue to provide adequate supplies of natural gas -- as I noted earlier -- if they are denied access for development of the most promising resource areas. As importantly, some method for successfully transmitting long-term price signals between customers and producers must be agreed upon soon.

As the Subcommittee members know, several traditional methods for trying to gauge customers' future gas needs and to acquire supplies to meet that demand are no longer available. Minimum bills have been removed by the Commission. Take-or-Pay clauses have lost their usefulness as a result of contract abrogation and the debilitating debate about liabilities in recent years. The industry has been attempting to find a new contract mechanism that will encourage long-term gas sales: provisions that will allow customers to indicate what value they place on securing long-term supplies and that will allow producers to indicate the price needed for investments to secure long-term supplies. Nearly all the industry agrees that the most promising method for such a mechanism is the gas inventory charge as suggested by the Federal Energy Regulatory Commission. It is important that some form of these inventory charges be implemented soon. We are aware of certain concerns that some have expressed about some aspects of these proposed charges and their potential impact on producers. We do not agree with many of the criticisms that have been made. More importantly, it should be emphasized that the mechanics of a particular GIC are far less important than ensuring that the Commission continue to harmonize these changes with the broader policy objective of maximizing competition in the production, transmission and sale of natural gas. The primary goal for gas policy must be the development of competitive markets and to the extent proposed GICs foster competition they deserve our support.

Mr. Chairman, the natural gas industry is making every effort to continue to expand toward a more competitive environment -- one that will be ultimately beneficial to all segments of the industry and to its customers. There is still much to do, but the outlook is very bright. We would ask your help in making it a reality.

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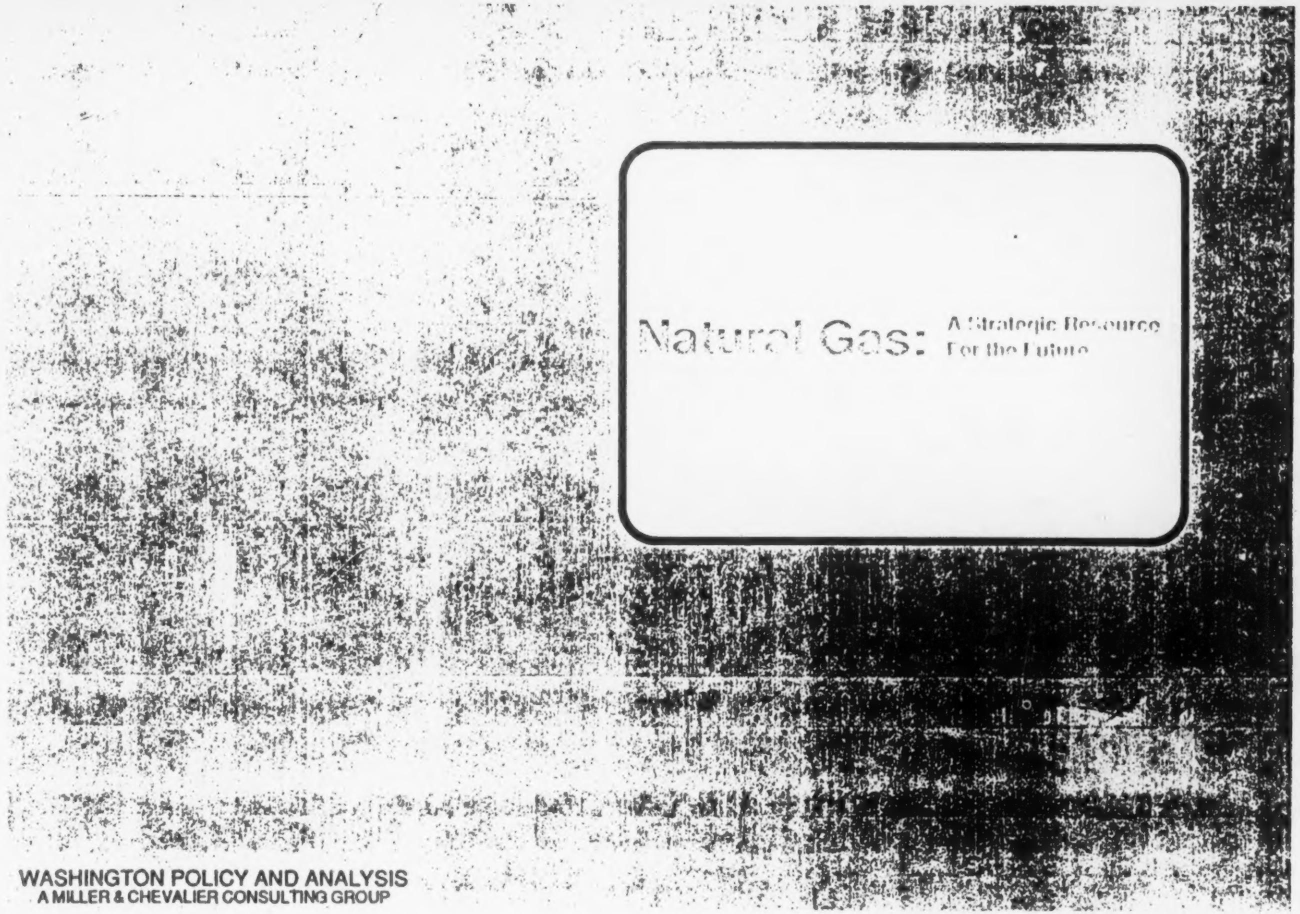

Natural Gas: A Strategic Resource For the Future

WASHINGTON POLICY AND ANALYSIS
A MILLER & CHEVALIER CONSULTING GROUP

A Research Report
of WASHINGTON POLICY AND ANALYSIS
A MILLER & CHEVALIER CONSULTING GROUP

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Natural Gas: A Strategic Resource for the Future

A Précis

It is time to get specific about adapting this country's natural gas *policies* to its economic, security, and environmental *goals*.

For the third year, U.S. oil imports have jumped. Given the realities of energy resource distribution around the world, the future promises a tightening world oil market, increasingly dependent on the volatile Middle East. Such a future poses risks of oil-price shocks and oil-supply disruptions in the 1990s . . . while concerns also grow about air pollution, acid rain, and other environmental problems. This study shows that over the next 20 years the United States has the ability to increase its annual use of natural gas by approximately one-third. If it does so, the nation and the world stand to be cleaner, more secure against potential energy supply problems, and better off economically.

The challenge to the new administration and Congress is that at this moment our country is not headed in a direction that makes this *possible.*

As things stand, neither the U.S. supply nor demand for natural gas would grow rapidly enough to do what political leaders, environmentalists, economists, energy analysts, and academics now agree should be done. But conditions can change and be changed . . . and this report suggests how a new national attitude about natural gas can be helped along.

Both presidential candidates in the 1988 election backed the broader future use of natural gas. Now that the election is over, attention must focus on "how we can get from here to there." "Here" is the still-conventional wisdom in energy circles that U.S. use of natural gas for the year 2010 is likely to be at virtually the same level as today's if present trends persist. "There" means a much enlarged consumption of natural gas, especially at the expense of imported oil.

In this study we asked a number of questions about the future of natural gas. First, we tried to discern whether there was any way natural gas could fill the larger role assigned to it by both sides during the campaign. Then we pressed on with the hard question of whether the nation would really benefit if it did. Our conclusions are positive on both points. Natural gas can play a bigger role, but is not a panacea; and its increased use is an indispensable factor in the kind of mixed-and-balanced energy equation that best suits the nation.

As the study progressed, it focused on *means.* We asked what was needed to change the results of the model projection of gas use by the WEFA Group from a modest growth scenario of "business as usual" to an accelerated growth scenario in a "new gas environment" (with worthwhile effects on energy security, national productivity/

competitiveness, and environmental quality). Surprisingly little, we learned . . . if supply and demand are *both* addressed.

Government and private-sector analysts should be especially interested in the *sorts* of assumptions about continuations or modifications to national energy policies that have been made here to test their combined effects. One set of mutually reinforcing actions by the federal government is outlined broadly on page 5 and amplified thereafter in the text. Individually, none of these steps may be terribly surprising to students or implementers of energy policy; but the fact that they are parts of an integrated approach is critical.

This is not to style our mix of policy options as a "take it or leave it" recipe. The fact is that natural gas is not a *perfect* fuel for all locations and economic sectors; nor is it one that can stand alone. A different mix could achieve similar results. But natural gas *can* play a larger role, and a mix of new policies can make a significant difference in energy security and the quality of our environment. Any combination of governmental choices in the real world involves tradeoffs, and both the President and Congress could fine-tune a set of proposals such as these in a way that U.S. consumers and producers of energy will find to their satisfaction.

From a practical political standpoint, it is hoped that this report can constitute a reasonable framework for discussion in the weeks and months to come. Wherever possible, the potential costs and benefits of various courses of action are at least summarized, and the far more comprehensive reports generated by individual participants in the study will be available to those who can profit from their detail.

It also became clear in the course of this study that new initiatives in natural gas policies alone would not do enough. Other vigorous policies to encourage domestic energy sources and to foster conservation are essential if the nation decides to slow the rise in oil imports from insecure sources while preserving a healthy economy and environment. These include policies to stimulate domestic oil production, promote the introduction of clean-coal technologies, seek further safe and economic development of nuclear-based electricity, use "renewables" to the maximum practical extent, encourage more efficiency in energy applications, and support basic research on promising energy technologies for the longer term.

We have not drafted this as a contentious document, but as a consensual one—with interesting and valuable results. For instance, some readers may be amazed that the following pages do not dwell on such long-debated questions as open access to gas pipelines. Yet the gas industry itself is not of a single mind about some such issues—let alone suggesting that all regions of the country or all categories of consumers might reach agreement on them. Not one of the policy options that *is* mentioned here is likely to be considered radical. All are based on cautious study and free exchange among experienced observers who have served Republican and Democratic administrations or who have worked in one segment or another of the natural gas industry over the past several years. Each has been asked to concentrate on findings and issues that can unite them.

The starting point of our study (and of this summary report) was a projection of patterns in U.S. energy demand for the year 2010. This baseline projection anticipated that technology and economics will continue to make the nation more efficient in applying energy resources—so that full-sized passenger cars in 2010 might routinely deliver about 50 percent more miles to the gallon than they do now, and each dollar of real gross national product (GNP) would be associated with the consumption of about 30 percent less raw energy in any form (moving well beyond all the conservation measures of the 1970s and 1980s). Furthermore, the base-case model was cautious in assuming a fairly modest rate of economic growth (an overall average of 2.5 percent per year); and it counts on the completion, licensing, and operation of nearly all commercial nuclear powerplants now under construction. Other modeling assumptions and approaches are reported far more fully in a separate publication.

The contrast between this base case (which foresees U.S. use in 2010 of natural gas that is equivalent to about 9 million barrels of oil per day) and the much higher supply-and-demand that the analysis shows resulting from the enumerated policy options (equivalent to roughly 12 million barrels per day) is striking.

These two hypothetical "cases" are presented graphically on the next page. Neither is a *prediction;* there are always enough imponderables to make long-term prophecy a fool's game. But the projection method is clear and open to inspection. The potential differences between these two prospects arise essentially from a few concerted "mid-course corrections" in federal energy policy. We are convinced that options of this type deserve examination *now.*

The bulk of this report asks a series of questions . . . and provides considered, cogent answers:

Where can all that gas come from? . . . and how is it to be delivered? Page 6

How and where can natural gas fit in ? . . . and how soon? Page 16

What does gas "buy" us in terms of energy security? . . . and at what cost? Page 25

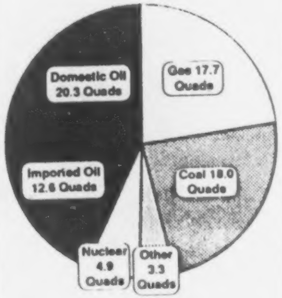
How much can natural gas do for environmental quality? Page 29

What are the implications for budget, overall growth, and international affairs? Page 34

The difference between this projection, based on "conventional wisdom" . . .

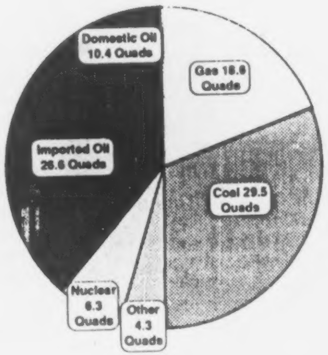
. . . and this one, based on "a new environment for gas" . . .

1987—U.S. Uses 17.1 Trillion Cubic Feet of Natural Gas



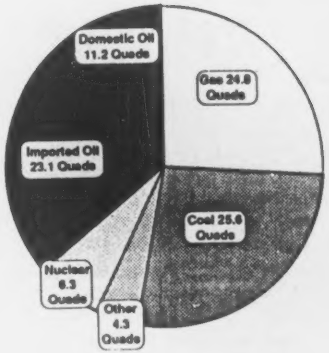
Total Energy Use—76.7 Quads

2010—U.S. Uses 18.2 Trillion Cubic Feet of Natural Gas



Total Energy Use—95.7 Quads

2010—U.S. Uses 24.1 Trillion Cubic Feet of Natural Gas



Total Energy Use—95.3 Quads

. . . came from certain budget-conscious assumptions about federal attitudes toward:

A "least-cost" strategy to achieve desired environmental standards

- Basing enforcement on *performance* rather than mandating specific control *techniques* (thus favoring such low-cost methods as trading emission "credits" and burning gas in conjunction with other fuels, in preference to coal "scrubbers").
- Monitoring compliance in terms of areawide "bubbles" rather than individual facilities (thus encouraging the selective, cost-effective replacement of older equipment).
- Assisting local efforts to clean up air pollution by specifying that federal funds for public transport fleets (for example, from the Urban Mass Transit Administration) be used exclusively for low-polluting vehicles.

Targeting of R & D

- Research *and* development on the geoscience that underlies natural gas production.
- Federal funding and other incentives for R & D associated with gas-use technologies—including advanced combustion turbines for generating electricity, cooling by gas, vehicles, and the "co-firing" of gas with other fuels.

Improvements in the "deliverability" of gas

- Use of all responsible procedures at the federal government's command to expedite the licensing of new capacity for pipeline delivery of gas to regions that are now heavily dependent on imported oil.
- Encouraging adequate storage of natural gas in the context of an emerging new supply-and-demand context.

Incentives to exploration and production

- Prompt identification and lease of the most promising federal lands where exploration can be deemed environmentally acceptable.
- Limited tax credits (for example, 10 percent for all exploratory drilling activity, plus 10 percent for redevelopment drilling in old fields with newly recognized additional potential).
- Adjustment of federal royalties to permit earlier recovery of investment in productive wells . . . and a sliding time-scale of royalty collections, based on market prices (but expanding ultimate return to the Treasury).
- Complete decontrol of wellhead prices for all gas.

Note that some of these policy options apply to basic gas supply for the nation, others apply to the demand side of the market equation, and a couple relate to both supply and demand. Each is described—with its "upside" and "downside"—in the text of this report and supporting publications.

Wherever possible, the effects of individual actions were factored into supply and demand estimates—although some are obviously difficult to quantify. It is clear that various elements of an entire program (this nominal one, or any other) *interact* to produce a cumulative result that can surpass the sum of its parts—so that concurrent action on *all* fronts is desirable if not essential.

Where can all that gas come from? . . . and how is it to be delivered?

The United States Has More Producible Gas Than Most People Thought

There is no doubt now that enough natural gas *can* be produced and delivered from secure sources at reasonable prices to let gas serve this country as an important "bridging fuel" to 2010—by which time even more-environment-friendly renewable sources might be nearly ready for widespread and economical use.

This represents a major turnaround in outlook. As recently as five years ago, the carefully prepared biennial *Projections* volume of the Department of Energy (DOE) went virtually unchallenged in asserting that new U.S. gas reserves were dwindling fast and that conventional production was likely "to decline at 2 to 5 percent per year from 1990 to 2010." Yet resource estimates made earlier this year by both DOE and the industry's Potential Gas Committee (PGC) agreed that there is enough gas left in the ground for today's technology to continue pumping it out economically at present rates for at least 35 years. An additional decade of supply awaits us in gas that could be recovered if prices at the wellhead rise modestly in the future to the equivalent of between $3 and $5 per thousand cubic feet (Mcf)—in other words, the counterpart in energy content of oil at roughly $20 to $30 per barrel today. Furthermore, even this fails to take into account future supplies of "unconventional" gas—the sort that budding technology might derive from sources such as coal seams and shale formations. Their development could extend the total available resources by another one-quarter to one-third.

What caused this fresh optimism about domestic supply? No new giant gas fields were discovered (although Mobile Bay and deep waters of the Gulf of Mexico show great promise). In fact, lower world prices for oil have drastically reduced U.S. exploratory drilling over the past three years—although the nation's *production* of natural gas has defied the gloomiest predictions and headed back up again. One reason for rising confidence about gas resources is that a better understanding of geology shows how irregular underground reservoirs of gas are—revealing that closer and better spacing of wells makes it possible to drain fields much more efficiently, even when only the conventional production methods are employed.

A knowledge-jump of this nature is hardly unprecedented. The internal combustion engine nearly lost the U.S. automotive market to steam-cars and electric vehicles early in this century, because gasoline supplies were feared to be inadequate—until new ideas about where petroleum existed led to finding the huge Spindletop Field. Shortly after World War I the domestic outlook for hydrocarbon resources was bleak again—until advances in geophysical surveying and production brought about development of previously unexpected new fields in West Texas. The long-term value of broadening continually our understanding of geoscience cannot be disputed.

The new DOE study gives a series of specific examples—along the Gulf Coast, in South Texas, and encompassing parts of Kansas and Oklahoma—where fields that had been abandoned or were assumed to be nearing total depletion are now diagnosed as holding up to 25 percent more gas than was estimated initially—in untapped reservoir compartments that simply are unconnected to those drained earlier. Apparently this holds true for many of the 10,000 fields the panel evaluated nationally. Much of the additional gas can be located and drawn off merely by sinking new wells between the old ones . . . and by putting wells closer together as new fields are opened up and old ones are extended.

Obviously, that process can be made far more efficient through geoscience research if it becomes possible to target such heterogeneous reservoirs more accurately (for example, through high-resolution seismic imaging) and to contact more of the gas-bearing rock (for instance, through advances in horizontal drilling). In many fields, older wells can now be reevaluated with technologies that were not available when these wells were drilled 10 to 40 years ago—with even newer methods in the testing stage that will make this process much more efficient in the 1990s. It should be possible to locate and reach gas resources that were bypassed initially but can now be connected to existing pipelines as deeper reservoirs are depleted.

The pattern of new gas discoveries in the United States has changed a couple of times over the history of the industry. Nearly half of all the 390,000 U.S. wells that have ever been drilled have been sunk since the mid-1970s; but the average addition to gas reserves *per well* dropped suddenly at that time to only about one-quarter of what it had been since 1900. The heartening news is that well output has held remarkably steady at this new plateau; and Professor William L. Fisher, of the University of Texas at Austin, offers convincing analyses to support the expectation that it will remain so through the next 300,000 completions. The gist of his interpretation is that few "elephant" fields remain to be found (with the possible exception of offshore—where the average well now produces 7 times as much as the national average in reserve additions—and in largely untapped Alaska). But there are many more small and moderately sized reserve pockets than had been recognized, and advanced technology has increased the success rate in locating them.

In our judgment—bolstered by discussions across the industry as well as with academics—modest tax incentives probably would trigger considerable additional investment in both exploratory drilling and "redevelopment" of old fields. For purposes of modeling, we tried to gauge the effects of a 10-percent tax credit in each case. In the case of redevelopment for older fields that are past exploitation by conventional means alone, "qualifying" fields might be limited to those beyond a certain age relative to discovery and "full" development and those whose annual production showed clear decline over a five-year period such as 1978-82 (before market conditions prescribed the curtailment of production for economic reasons apart from resource depletion).

Secure Sources Include Some Gas Beyond the Borders of "The Lower 48"

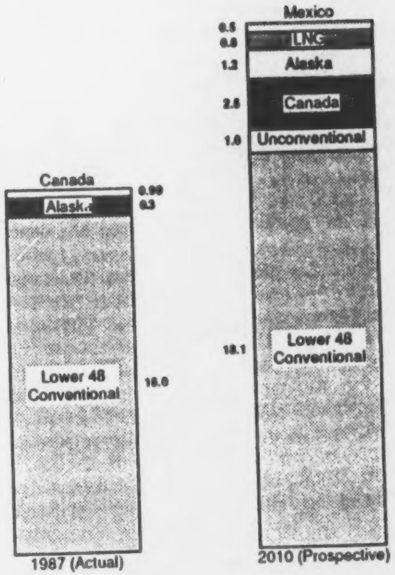
In the scenario for accelerated gas production and use, it is estimated that annual conventional domestic output (exclusive of Alaska) can actually increase by about 2 tcf—including a rising contribution from "tight sand" deposits. Also, unconventional production is projected to become more economically sound as energy prices rise in response to tightening petroleum markets around the world during the 1990s and geoscience leads to advanced production technologies.

This means that domestic wells in the "Lower 48" can remain the backbone of national supply for decades to come. But there are four other sources of natural gas we should also be able to count on in a projected total of 24.1 tcf annually by 2010—Canada, Alaska, Mexico, and some imports in the form of liquefied natural gas (LNG).

Canada: In 1987 the United States was already importing more than a trillion cubic feet of natural gas each year from its good neighbor to the north. Preliminary data show that this level may climb by another 25 percent this year; and the interrelated dynamics of Canadian reserves, pricing, and pipeline capacity suggest that our net imports from Canada might hit 1.5 tcf as soon as 1990. This would leave ample time in which to develop the delivery infrastructure and market to support a 2.5-tcf annual import flow by 2010.

Closer trade relations with Canada are mutually beneficial in energy. For Canada, the gas sales envisioned would create the incentive and the opportunity to develop frontier resources that would increase its reserve base dramatically in years to come. In return, this country can foresee a secure supplement to domestic production at competitive prices.

Sources of Cost-Competitive U.S. Gas
(trillions of cubic feet)



Alaska: Alaskan gas resources are substantial—with the known reserves of 26 tcf on the North Slope alone far exceeding a full year's supply for the entire country; but these have barely been developed because markets are so distant. The sparsely populated state is self-sufficient in satisfying its own present demand, of course; but this amounts to only about 300 billion cubic feet (bcf) per year. Another 50 bcf annually is being converted into liquefied natural gas for shipment via refrigerated tanker to Japan.

Under appropriate market conditions (that is, when the real price of gas approaches today's equivalent of $4.00 per Mcf and looks as if it is likely to stay at that level or higher, while substantial demand exists for gas as a substitute for oil), Alaska could become a significant supplier by pipeline to the Lower 48. Precise timing is difficult to forecast, but it is reasonable to conjecture that a suitable pipeline could go into service within the first decade of the 21st century. This was one of the assumptions used in projecting supply to support the "accelerated U.S. gas-use scenario" highlighted on pages 4 and 5.

Mexico: Large gas imports from the south were close to becoming a reality more than a decade ago; but then progress toward a bilateral agreement ended abruptly and Mexico decided to focus first on developing more domestic applications for its gaseous fuel. A new U.S. administration that has expressed its goal of improving political and economic ties between the two countries should have ample opportunity to revive the project during the 1990s; and those international imports by pipeline could easily begin by the turn of the century—rising to perhaps 500 billion cubic feet by 2010.

Mexico's proved reserves of gas are nearly 40 percent as large as those in this country (76 versus 192 tcf), although its total resources (about 200 tcf) are only about one-fifth those of the United States. Because Mexico's annual domestic consumption is still only about 1.25 tcf, however, vigorous growth in our country's demand could well prove attractive to a market of common value.

LNG Tankers: Norway, Algeria, and Nigeria are all possibly reliable suppliers to the United States once trade in liquefied natural gas to this country starts up again—perhaps by 1990. Development of the North Sea fields in particular has already made natural gas more promising as a European fuel, but it has also brought into the spotlight vast additional reserves of gas that ought to be co-produced while North Sea oil is being tapped. At the same time, unused LNG tankers are available now at reduced cost.

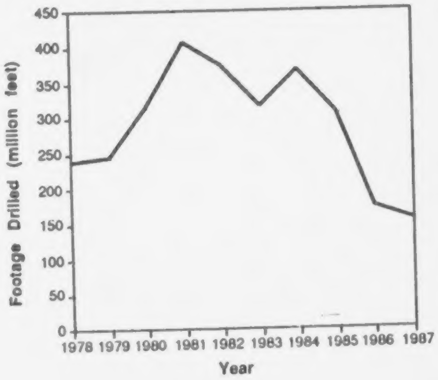
If adequate demand for gas develops here, there seems to be no question but that LNG will be able to serve certain markets—even now, but certainly in any situation when pipeline capacity from the major producing areas might have difficulty satisfying some regions' demand. By 2010 such shipments were projected in the WEFA model to total 0.8 tcf. However, no additional deep-water U.S. port facilities suitable for receiving LNG were assumed before 2010.

The Level of Drilling Is a Separate Issue From Basic Resources

Despite our country's huge hydrocarbon resources—even in the Lower 48—not nearly enough exploratory drilling is under way at present to ensure that these will be converted into "proved reserves" and final production of gas at a rate that could accommodate the accelerated-use schedule postulated by this study. The return to actual and potential producers of oil and gas is currently too small—partly because the price being paid for delivered gas is low, and partly because the combined "take" from royalties, production taxes, and state levies is relatively high (for example, totaling an average of about 44 cents per Mcf at a federal leasehold well off the coast of Louisiana, at a time when the producer is receiving only about $1.75 in all for each Mcf at the wellhead).

Part of the problem lies in the so-called "gas bubble"—a temporary imbalance between supply and demand that was brought about largely by a coincidence of circumstances: a) rapid price increases in the early 1980s, driven by peculiarities of the Natural Gas Policy Act; b) economic restructuring across the nation, and a general economic downturn in 1982; and c) vigorous energy conservation steps, which dampened demand for all fuels. Most of the experts involved in this particular study believe that it is fading away and should disappear by 1990.

Oil and Gas Well Drilling, 1978-1987

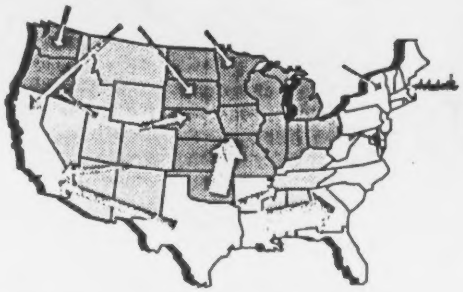


Part of the difficulty also arises from the fact that wellhead prices for some sources of natural gas are still technically under federal regulation—although three-quarters of all gas is effectively deregulated.

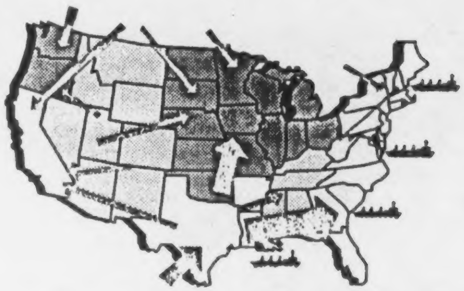
A major contributing factor, however, is the large amount that must be paid out in royalties and taxes as soon as a well enters production. Drilling is a capital-intensive business—and a risky one to boot. The theory behind delaying government royalties and taxes (another policy option assumed in this report) is that faster payoff to an explorer and producer of gas should encourage the search for new reserves and the brisk development of wells that prove successful. Ultimately, this leads to speedier and more efficient application of the nation's resources. Thus, it also increases government revenue overall.

Some 1.1 million miles of pipeline are used in the United States today to gather, transmit, and distribute natural gas. We know that this network is capable of delivering more than 23 tcf annually as it stands, because the smaller pipegrid that existed 15 years ago actually handled more than 22 tcf in 1973. Within limits, increased pressure can easily and safely raise the volume of gas being carried over long distances.

1988 Gas Transmission Patterns



2010 Gas Transmission Patterns



"Packing" the lines is a common practice during periods of high demand (for example, in cold weather, when the requirement for gas heating in residential and commercial buildings soars). Even this could not accommodate the sharp seasonal variations that occur, however; so local distribution companies (LDCs) as well as bulk suppliers have far greater underground storage capacity than the average gas user ever imagines. At the end of October 1986, for instance, the amount of gas in such storage across the United States exceeded 7 tcf. This is the heat-equivalent of far more than a billion barrels of oil—thus representing twice as much energy content as the federal government's massive Strategic Petroleum Reserve (SPR), which was created and is continually being augmented as an emergency safeguard against future disruptions in crude oil supply. And the Energy Information Administration now estimates the industry's *total* storage capacity for natural gas at something above 8 tcf.

Spare Pipeline Capacity, New Routes, and Storage Fit into the Mosaic

But another huge question about the timely delivery of natural gas remains: "Do pipelines carry it to where it will have to go?"

The answer is "No, not completely." A possible breakdown of how the yearly demand for 24 tcf of natural gas might evolve in this country is discussed in the section of this report that begins on page 16; but the two generalized maps above exemplify at a glance how some gas transmission patterns might have to change. Although most gas in 2010 will come from the same geographic regions as it does now, the Mountain States should be a more significant domestic supplier. Alaskan gas ought to be available by pipeline, and perhaps half a tcf of Mexican gas may be in the U.S. supply picture. LNG should be arriving from overseas. Such knotty questions as how future air quality standards will be specified leave the *exact* pipeline needs unpredictable from the distance of a couple of decades.

When everything else is equal, history has shown that the demand for natural gas goes hand in hand with its availability. Gaseous fuel was used sparingly by population centers along most of the Atlantic Seaboard through World War II, when it was still being *synthesized* primarily in local "gas works." Once the big wartime pipeline for oil called "Big Inch" was converted to deliver *natural* gas from producing areas in the south, however, both the means of applying it and its total consumption expanded impressively. Even now, the populations of Louisiana and Maryland are almost identical in size; but the first of these two states (in the midst of gas-producing country) uses more than nine times as much gaseous fuel as the latter (where transport costs are higher).

If the Northeast (which is still heavily dependent on oil) wishes to substitute more gas, hundreds of miles of new pipeline will have to be installed. In fact, the Federal Energy Regulatory Commission (FERC) has recently granted construction permits for about a dozen additional gas-transport facilities for that area, and these will boost receiving capacity there by nearly 25 percent.

Unfortunately, potentially avoidable regulatory delays in the permit-granting process have been one of the chief constraints on the expansion of gas markets. Recently, FERC speeded up its own activity by declaring an "open season" for Northeast projects, during which a number of similar or related applications that have been stacking up can be considered simultaneously. Still, federal regulators have not shown enough scheduling and coordinating discipline thus far to produce appropriate speed in licensing pipelines into heavily oil-dependent regions.

Federal initiatives alone might not break the logjam completely, because state public utility commissions (PUCs) and other authorities below the national level are usually also required to grant permission in advance for such construction. Nevertheless, Congress and the administration can set an important example if the consensus emerges, regionally and nationwide, to boost the possible use of gas on environmental, economic, and security grounds.

It would have been far beyond the scope of this study (as well as presumptuous) to try to draft either legislation or administrative rules to facilitate the building of new pipelines where needed. The policy option we have surfaced in this regard needs detail work. Still, we feel confident in offering some general guidelines, which were observed in our modeling effort: 1) Whatever new steps are taken should be responsible ones from the standpoint of environmental protection. This was an easy stricture to accept, because once underground pipelines are in place they do not represent either an unacceptable threat to public safety or any insult to aesthetics. 2) Special consideration might well be given to applications for new pipelines that can serve areas that are heavily dependent now on other fuels, for which the substitution of gas offers demonstrable benefits. A similar case can be made for regions in which dangerously shrinking reserve margins for electricity-generating capacity point to gas-fired turbines as the most practical and timely solution. On both counts, the policy envisioned appears to be fundamental in permitting supply and demand to grow in tandem—as they must.

Additional gas storage, mentioned earlier as a possible insurance system to protect against future global oil supply problems, is also a means in itself to expand current domestic supply. Producing wells churn out gas continuously, and pipelines will have to be filled as much as possible on a year-round basis if they are to render maximum service. Yet demand is bound to remain seasonal to some extent. An even more comprehensive storage system—decentralized so as to offer maximum flexibility—can "level the load," much as pumped-storage reservoirs do for generators of electricity. With either energy source, this approach makes possible maximum delivery of the product in the most economical way.

Various Policy Steps Reinforce One Another in Ensuring Gas Supply

It cannot be repeated often enough that supply and demand interact. So do a number of the government policies addressed in this report—especially in regard to bringing the United States' secure supply of natural gas to the level discussed by 2010.

Today's clearer understanding of the heterogeneous nature of underground gas reservoirs means that U.S. *production potential* has increased. Thus, the producible domestic *resources* of natural gas (the total amount we may reasonably count on drawing from the earth ultimately, using specific technology and confining production costs to certain levels) are larger than was thought previously. But the fact persists that too little is being done right now to *pinpoint* new reserves so they can be brought to the surface. Unless there is a turnaround, the level of reserves will begin to erode again next year . . . and in the years to follow.

No single, simple solution to the dilemma appears to exist. Instead, a variety of *coordinated* actions came to mind in devising a model that might take full account of the new national attitude toward gas.

Companies in the U.S. gas industry, large and small, are more likely to step up exploratory drilling once again if they have somewhat greater assurance that the fruits of their investment will be marketable at returns that are based on risk and *true* value of the commodity—rather than on oil-price manipulations by an international quasi-cartel or on gas-price ceilings imposed by their own government. Deregulation of wellhead prices is important; and limited tax incentives (only for exploration or for redevelopment drilling in older fields that now stand to be rejuvenated) appear to be needed as well—because of justifiable fears that OPEC behavior can force world energy prices *down* capriciously as well as *up*.

Perhaps 35 percent of the gas that remains to be produced by conventional methods in the United States lies in areas under federal jurisdiction. Rather than exclude blocks on the map wholesale on the basis of emotion and political impulse, it seems to make more sense to establish priorities on the basis of the relative likelihood that gas might be found. This may require something of a public education program, because it is not generally understood that *most* exploratory drilling efforts are destined to wind up as "dry holes." Environmental risks will never be eliminated completely either. Despite these cautions, an intelligent and informed balance needs to be struck between the equally important goals of resource-need and dedication to keeping our land, air, and water in good shape. Once it has been established with reasonable confidence that attractive targets exist for environmentally sensitive exploration, development, and production, such areas should be made accessible (through a sound competitive bidding procedure)—so that the private sector can undertake the job.

Although it seems safe to forecast that energy prices will escalate over time, they will almost surely not rise along a smooth curve. New drilling (which has been cited as a key ingredient in increasing future supply) would be likely to increase still more if government royalty payments could be deferred until the initial capital investment in any successful well had been covered. Production certainly would not cease at that point, because profits would continue so long as revenue from the gas was adequate to pay operating costs and a full, *higher* royalty. Analysis shows that this would bring a greater return to the government, so this is not a matter of authorizing subsidies.

Even before drilling begins, the recent hike in resources based on strategic "infill" production shows that research in geoscience can pay large dividends. The federal government has been committed nominally in recent years to support meaningful R & D on energy topics that are basic to resource development; but budget limitations have held actual DOE expenditures in this field to minimal levels. This year, however, the Department began a three-year, $22.25 million joint research venture with the Gas Research Institute and the State of Texas to develop and demonstrate cost-effective approaches to recovering additional reserves from conventional gas reservoirs.

More opportunities exist: efficiency in finding and developing a very large number of small-to-medium-sized gas sources is the key to economics—so that a national "reservoir framework" and trustworthy "reservoir models" would operate synergistically with research on high-resolution geophysics and better geostatistical methodologies. Broad R & D on drilling and hydrocarbon-recovery techniques also seem appropriate for cost-sharing.

Once again, the framers of this report recognize that they are clearly not as well equipped as the President and Congress to decide how these requirements compare with other national needs within the strictures of Gramm-Rudman and a clear resolve to limit the deficit. However, it seemed reasonable to assume that an appropriate level to *accomplish* a great deal in programs of this kind might be a total of about $100 million per year for several years—divided on approximately a 40-60 basis between gas and oil. Laboratory and field research needs to be accompanied by some effort in actual *demonstrations* of development work by joint ventures involving the government—especially when federal support goes beyond basic geoscience to advanced drilling and production techniques.

The long-run payoff to the nation can be great from such relatively minute taxpayer investments as were assumed in this projection, but fresh invention and creative perceptions of nature do not appear overnight. If we are pointing toward the year 2010, fiscal year 1990 will be none too soon to begin.

In the case of natural gas, furthermore, it has already been noted that *availability* is as critical as basic supply. The existence of an adequate delivery network—made safer and more efficient by increased storage capacity—is an additional constituent of an overall national commitment and plan that cannot be overlooked.

The final section of this report examines the respective costs we calculated for all these plan-components—along with their potential benefits, to the extent they could be quantified. Suffice it to say at this point that some program of this overall shape and scope appears to be worth doing.

How and where can natural gas fit in?
. . . and how soon?

Relative and Absolute Prices For Energy Will Underlie Gas Substitution Patterns

Projecting the exact way in which one-third more natural gas might be used effectively in this country by 2010 is far more complex (and subject to change) than demonstrating that a reliable and reasonable supply to support this level of demand can be developed. However, the model results were encouraging. Clearly, more gas use *can* make economic sense.

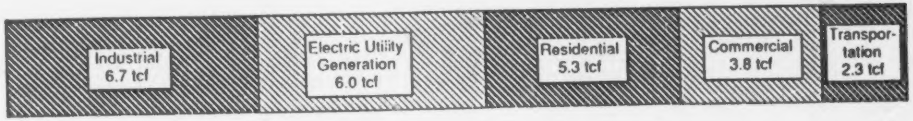
The graphics on the following page present one scenario of U.S. energy consumption (among many that could be proposed for the same time frame with equally sound reasoning) in which there is a cost-practical division of about 24 trillion cubic feet of natural gas by use-sector. We believe that market-based forces could bring supply and demand into a healthy balance at this level without the sort of massive interventionist energy policy that foundered in the past (for example, fuel allocations on the demand side, or the Synthetic Fuels Corporation on the supply side).

The degree to which natural gas substitutes in the future for oil (to make U.S. energy supplies more reliable), for coal (to limit air pollution and acid rain), or for any other energy source depends heavily on what the prices of gas will be *to various potential consumers*—especially in comparison with what the same individual, company, or institution would have to pay if another energy source were chosen instead. Such "burner tip" prices for gas vary appreciably now—not only because of differences in pipeline distance from one part of the country to another, but also because the rates at which gas may be purchased from a regulated utility company by any specific *category* of customer (residential, large or small commercial, industrial, electrical generating utility, and so forth) must be approved by local public utility commissions, whose policies are not uniform.

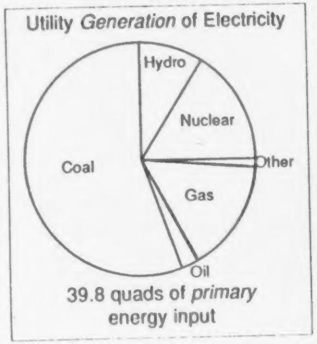
This study accepted the broad consensus opinion that "real" energy prices will rise after a period of relative stability—though not as steeply as was generally suggested a few years ago. We assumed that the average price of oil to U.S. refiners might rise to $37.50 per barrel in terms of 1988 dollars by 2010. But we estimated that the wellhead price of domestic natural gas would increase at a *faster* rate—to $4.50 per thousand cubic feet. Coal at the minehead, on the other hand, was pegged at an average of $34.70 per ton by 2010—not much more than it has been in recent years.

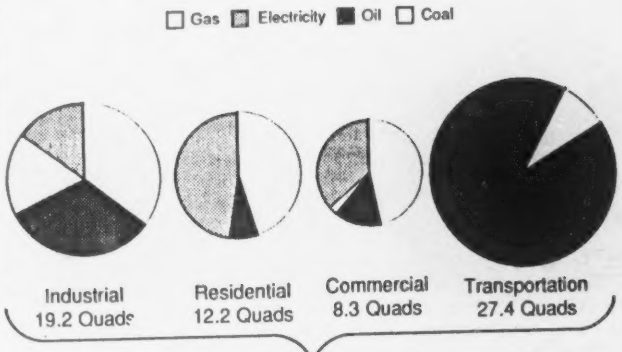
The very substitution of gas for other fuels affects the prices of those other energy sources too, through simple competition. As demand for oil softens, for instance, sellers of the fuel find it more difficult to keep the price up. To the extent that gas replaces oil, gas thus undercuts its own competitiveness in terms of comparative dollar-cost per Btu (British thermal unit). At the

One Way to Utilize 24.1 tcf of Natural Gas Economically in 2010:



. . . making these contributions to the respective energy-using sectors of the U.S. economy:





These end-use numbers include heat-equivalent of electricity *as delivered*.

Annual use of a "quad" (one quadrillion British thermal units) = generic equivalent of about half a million barrels of oil/day.

same time, however, more widespread use of natural gas should tend to reduce even further the capital cost of certain types of equipment that employ gas—through the cost-saving mechanism of volume marketing and mass production. And the overall cost of using one fuel in preference to another may depend as much or more on the amortization of equipment as it does on how much it costs to fill the tank.

In the case of oil and gas, there is the added complication that both of these fuels sometimes flow from the same well; and the obvious divergences in their price-trends depend on numerous other factors. We tried to consider many of these in the model, but overconcentration on methodology in a summary report of this sort might only obfuscate some of our most important conclusions in regard to potential demand—which are these:

- An overall energy demand for roughly 95 quads was projected in the "accelerated gas use" case for 2010, slightly less than the 96 quads in the "baseline" case. The use of more gas *in the roles projected here* would tend to reduce the total amount of energy required to provide specified services or maintain a given output—because of greater efficiency in the technologies envisioned (especially combustion turbines). Counteracting this effect is the fact that economic activity would simultaneously be encouraged to *rise* (based partly on stimulation of the domestic gas and oil industry, and partly on an improved trade balance), drawing the demand for energy upward along with GNP. These "big picture" matters are reviewed in the international and macroeconomic section that begins on page 34.
- U.S. demand for natural gas might rise in a relatively smooth curve over the next three decades (and, in fact, this is the way it was projected in the computer analysis of our model—as shown on the adjacent graph); but this *need* not be the case. Judging from historical precedent, demand seems almost as likely to increase in spurts—either as gas-using technologies such as combined-cycle turbine generators, dual-fuel boilers, and

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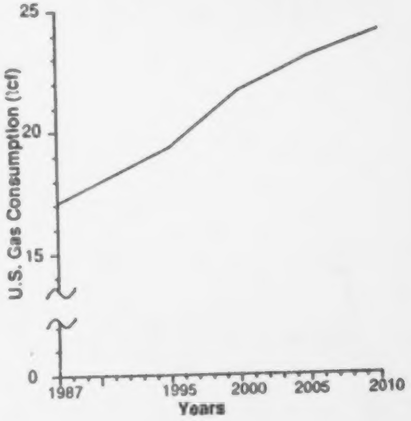
The WEFA Model Projected Gas Use To Increase In this Fashion, But Rises Might Come In Steps



vehicles fueled with compressed natural gas (CNG) are popularized nationwide, or as greater pipeline capacity expands regional markets (most logically, in New England).

- A major force driving the introduction of more natural gas into the U.S. economy in the future could be an effort to meet environmental standards in the most cost-conscious manner. (A section dealing specifically with this starts on page 29.)

In many areas, the local suppliers of gas and electricity have been fierce competitors. To some extent this will continue—particularly where the nascent technology for gas-cooling starts to challenge electric heat pump systems. However, the relationship between the gas and electricity industries overall might be in for some basic changes—as the former becomes a crucially significant supplier to the latter.

For a number of reasons, the demand for electricity is expected to grow more rapidly than the consumption of energy overall. Our assumption was that the growth-ratios of electricity use and total energy use to GNP would be 0.8 and 0.7, respectively, between now and 2010. Nevertheless, the construction of new generating capacity in this country has slowed precipitously. We are frequently reminded that it has been almost 15 years since the order was placed for the last of the nuclear powerplants still being built, but construction of large coal plants has also slowed. The Department of Energy was consciously conservative in its *Energy Security* report nearly two years ago when it warned that at least 100 gigawatts of additional generating capacity appeared to be necessary by the turn of the century . . . and hinted graphically that the potential shortfall was likely to widen thereafter. Yet utilities are still loath to place long-lead orders for capital-intensive fresh construction.

Apart from the special advantages of natural gas as an "environmentally benign" heat source for generating electricity, gas turbines inherently are easier and less costly to *build* than steam-generating plants of any sort. For this reason, they offer the best current hope in closing the "capacity gap" as it becomes sufficiently critical to threaten brownouts in certain parts of the country. With all this (and more) as background, we felt confident with a detailed analysis that showed gas supplying nearly one-sixth of the primary energy used in generating electricity by 2010. **This alone would require about 6 trillion cubic feet of gas annually, or more than twice as much as is being used now by the electricity industry.**

Industry and Vehicle "Niches" Complement Generation Market: Tossup Seen In Cooling

The new **transportation** role we postulate for gas lies more in a series of pinpoint targets—the so-called "fleet" markets, especially in regions where it will continue to be difficult to meet air-quality standards.

Natural gas has been used on an experimental basis for two different types of vehicles—those that carry cylinders of highly compressed gas as fuel, and those that can substitute methyl alcohol (methanol) for gasoline in somewhat oversized, but more-or-less conventional tanks. Theoretically, methanol can be manufactured from coal or vegetable matter; but it will be a very long time before its unsubsidized production from either of those feedstocks can match the economics of using natural gas as a chemical base. However, in this study we calculated only the effects of employing CNG vehicles on a large scale, because (paradoxically) their proportional demand for natural gas is somewhat smaller than is required in the overall methanol cycle and we wished to be conservative in estimating the potential market for gas in 2010.

Whether CNG or methanol eventually becomes the gas-based fuel of choice as an alternative to oil-based products in road transportation, it will probably enter the market first on a broad scale via specialized vehicles rather than ordinary private autos. An ongoing DOE study has alluded objectively to some of the reasons behind this in the preliminary reports it has issued, but they boil down to the following: the size and weight of tankage (which is easier to accommodate in larger vehicles); greater capital cost (which fleet owners might absorb more readily in anticipation of longer-term benefits); and the need for convenience in having places to refuel while a general distribution network is evolving (something many fleet owners are capable of providing for themselves). It is worth adding that essentially the same ground rules will apply to commercial penetration of the transport market by electric vehicles—which must still be considered prospective competition for gas-based taxis, buses, and local delivery trucks.

The final demand model in this study assumed that no more than one private car in 20 would be using natural gas as its primary energy source by 2010 . . . and that CNG vehicles would constitute only one-quarter of the private fleets in the country. But at the same time it seemed realistic to estimate that 75 percent of all city buses might have switched to CNG by then. With all else equal, the prospects of reducing local air pollution by this means can obviously have great appeal. And it would be relatively easy for an administration pledged to help preserve environmental integrity to specify that funds provided through the Urban Mass Transit Administration (UMTA) or any other federal agency be used only for less-polluting vehicles—with the exact choice to be left to local authorities.

With these assumptions, we judged through model runs that an extra 1.7 tcf of gas would go into the transport sector for motor vehicles each year by 2010. This would be in addition to 0.6 tcf of gas that would be required to operate pipeline compressors around the nation—a use that is already commonly tabulated in energy-consumption tables as an input to transportation.

The other big new "niche" markets that we could foresee for natural gas are in industry. Even a cursory examination of construction filings for cogeneration facilities suggests that gas is the most favored of all fuels for this process—in which the end-results are both usable heat and electricity. Furthermore, the secular trend nationally toward a less energy-intensive service economy might combine with improvements in efficiency to slow down industrial consumption of energy in general; but a combination of economic, security, and environmental considerations should make gas a stronger contender for industrial use in general.

Residential consumption shows less opportunity for gas-demand growth overall. Despite regional limitations now, gas is already supplying heat to more than 45 million of the nation's 88 million dwelling-units. In addition, approximately 34 million American homes also use gas now for cooking. Although new home customers for natural gas will appear in some areas where they have been rare, many will be able to achieve the same results in the future by expending less energy of *any* sort. Improvements in the efficiency of gas furnaces, coupled with slow but continuing improvement in the average insulation of our housing stock, will tend to cut the gas requirements per residence. Microwave ovens and electric heat pumps also compete with gas (although gas-fired heat pumps have been under development for years and might make a dent in the future).

The biggest imponderable in future **commercial** gas demand will be space cooling. Much of the rapid increase in use of electricity during recent years (especially at seasonal peaks) has been for air conditioning; but the contest between gas and electricity in this arena is not over. Double-absorption cooling by gas is ready to pose a major challenge—as are very efficient engine-driven gas "chillers"; and this potential was factored into the various demand scenarios we considered. Again, however, we were conservative—assuming merely that targeted R & D could help gas to increase its share of the commercial cooling market from its current 6 percent to a still-modest 10 percent between the 1990s and 2010.

If this country increases its emphasis on natural gas, the actual fuel substitution that takes place will depend on the sectors in which switching or replacement goes on. That is one reason why this study took such pains in dissecting potential demand growth.

Natural Gas Could Replace About 1.5 MMBD of Oil More
. . . And Augment Clean Coal

In the scenario pictured on page 17, the nation would *use* approximately a million and a half barrels of oil per day less by 2010 than in the baseline case (although imports would be affected more than that because of a 600,000-barrel-per-day stimulus to domestic production). Slightly more than half of the oil *replacement* would be in motor vehicles, and most of the rest would be divided between industrial and electric generation markets. However, generators of electricity have already slashed their dependence on oil—relying on it for only a few percent of their total energy input in recent years (even after the price of oil plummeted in 1986). The baseline model for 2010 projected little oil left in that sector for gas to replace, but gas in combustion turbines would be substituting for some oil as well as coal. This fuel-switch would be dictated by economics, but only because the partial use of gas (either on a seasonal basis, in "co-firing" with coal, or both) is quite likely to be the most cost-effective way to meet environmental standards.

The prospect of using more natural gas for generating electricity does not eliminate the importance of pressing ahead vigorously in the United States with coal production or with R & D on more economical clean-coal technology. Even with the accelerated gas use we have projected for 2010, this country would be using approximately one-third more coal than it does now. With domestic consumption around 1.2 billion tons annually by then, export markets can be envisioned that might coax U.S. production into approaching a billion and a half tons. Because the national insistence on air quality is not expected to evaporate, better ways must be found to burn even high-sulfur coal acceptably. Mandating the use of "scrubbers" raises new environmental problems in itself (besides reducing efficiency and ballooning costs); but such technologies as fluidized-bed combustion hold out more hope.

Role of Gas In 1990s Might Switch Emphasis In Years That Follow

The principal opportunity to expand gas use during the next decade is in supplying electricity.

There are relatively few days during the year when low "reserve margins" of generating capacity pose their most serious danger—and then only during the hours when customers' demand for power rises to a peak. Because air conditioning has such a voracious appetite for energy, the public tends to associate such problem periods with high summer; but the widespread use of electric heating in an area like the blustery Northwest makes for "winter-peaking" utilities there . . . and the popularity of electric heat pumps in the Mid-Atlantic States is moving their generation load-curves into a characteristic shape that has twin peaks—one in cold weather and one in hot.

Conventional turbine-generators fueled with natural gas have been used for some time as "peaking units"—expressly to meet occasionally very large demand. In this role, their relatively high fuel cost per kilowatt-hour (as compared with "baseload" steam-turbine plants) has not been too limiting. Nor has the fact that many of today's gas turbines might face technological problems if they were forced to operate continuously on a year-round basis instead of serving for intermittent spells as needed.

The maximum electrical output of the largest "combustion turbines" (so-called because the high-temperature combustion gases themselves spin the turbine blades) is fairly small in relation to the customary baseload plant. This can be an advantage in an era of fiscal caution in meeting demand projections, however, because it means that capacity can be added in smaller steps. Because these turbines can be ordered from production lines with only a low capital investment, we expect them to be the quick choice of many utilities to protect safe margins of reserve capacity that are threatened during the 1990s.

Gas can also be burned under conventional steam boilers to generate electricity; and, in areas near producing fields, such systems can clearly be economical for base loads. But until the Powerplant and Industrial Fuel Use Act (FUA) was repealed in 1988, it had actually been against the law for years to build utility or industrial boilers using gas as a heat source. This outmoded restriction was motivated by the common view in the 1970s (since proved incorrect) that our country was on the verge of exhausting its domestic resources of hydrocarbon fuel completely. Elimination of the ban forms part of the "new environment for gas."

Combustion turbines are starting to play a different role too. Despite FUA, new gas turbines *have* been permitted . . . and, in fact, they have even been encouraged (in a way that may not have been foreseen by legislators) through the Public Utility Regulatory Policies Act of 1978 (PURPA).

One of the purposes of this act is to promote cogeneration (albeit outside the electric utility industry), but roughly half of the heat-and-electricity systems that grew out of the initiative are fueled by gas. And gas turbines have been especially favored because of their low-polluting features and their high *overall* efficiency when exhaust heat is put to use.

It is the efficiency factor that presages eventual use of improved combustion turbines for baseload generation. When exhaust heat from a gas turbine is used to operate an integral *steam*-based generating unit, the "combined cycle" system gets an eye-opening power payoff from its input. About 47 percent of the heat is converted into electricity—compared with efficiencies in the 30s for conventional steam plants.

More R & D might even help baseload layouts of linked combustion turbines fueled by natural gas to become a standard item. At present, their major prospective competition appears to be combined-cycle turbines fueled by gas that is synthesized on-site from coal—an integrated system that has performed well in limited testing. Yet some utilities have already announced plans to install only the turbine segment of such a system at first—which means that natural gas would be the initial fuel, presumably to be displaced only if coal gasifiers offered some recognizable advantage.

We can easily foresee gas demand in the United States growing in discrete stages over the next 30 years—with baseload generation gradually superseding gas peaking units in emphasis within certain areas, and the number of vehicles based on natural gas fuel starting to grow sharply later on.

History has shown that market competition generally results in better products. Consumer choice is not inevitably based on price alone, but can accommodate a remarkable variety of divergent goals—based on individual perceptions of needs.

Policy Recommendations Stress Broader Choice, But Let Users Decide

America's energy requirements for the future involve security of supply, convenience, and the preservation of a safe, healthy, wholesome environment. Natural gas certainly can do more than "conventional wisdom" now says it is likely to do in satisfying energy needs across the board; but we believe that it would be a mistake to order—or simply subsidize—gas use. Therefore we have assumed in our modeling that free choice among fuels (or ways of using specific fuels) will be allowed to prevail. City bus systems would decide for themselves whether the low-polluting vehicles they buy with UMTA money should use CNG, methanol, chemical batteries, or some sort of exhaust-collection devices. Building owners would certainly choose on their own between cooling by electricity or gas. Those who generate electricity (for their own use or for sale) would not be *directed* to use scrubbers as the only allowable method of controlling emission levels—any more than they would be *forbidden* to use any particular fuel (even oil).

The only purpose in targeting R & D (largely through cooperative ventures with the private sector) toward certain *gas*-using technologies would be to make sure that certain useful and practical options we can now envision will be available *in time to make a difference.* The available choices should be broad.

Obviously, the same principle can be applied to an assumption we made about deliverability of gas. More than a century ago, the federal government helped in a number of ways to build railroads where none had ever existed; but today, ironically, the inverse is true for gas pipelines. Far from facilitating the creation of a new transport and storage infrastructure, government has often been the principal impediment—through slow-paced regulatory procedures.

An enormous transmission and distribution network for natural gas already exists; and if potential demand is evident in areas that are not yet being served optimally, we are confident that private capital will be available to finance new pipelines. All the federal government needs to do is to see that *needless* barriers to construction are removed.

The exact way for FERC to expedite its own licensing procedures is up to FERC. We believe that this *can* be accomplished, and we have only assumed that it *will* be. Beyond that, its leadership by example might do wonders in affecting the speed of public utility bodies at the state level. Even if the only step in common were to arrange for state and federal hearings on pipeline construction applications to proceed *concurrently* instead of *consecutively*, we have ample anecdotal evidence that the improvement would be felt almost immediately.

Because of the structure of growing demand, it has been assumed that special consideration in the pipeline approval process might be given at least to regions such as the Northeast—where reliance on imported oil is particularly high and where last year's *Energy Security* report from DOE noted there will be a need for "new power supplies sooner than other areas."

What does gas "buy" us in terms of energy security?
. . . and at what cost?

By 1993, according to baseline projections, the United States could be importing half of all the oil used here. Given the distribution of oil-producing capacity around the world, this country and its allies probably will have to rely on the tinderbox region of the Middle East for much of that supply. The perils to energy security in that case have been well documented elsewhere; they are undeniable.

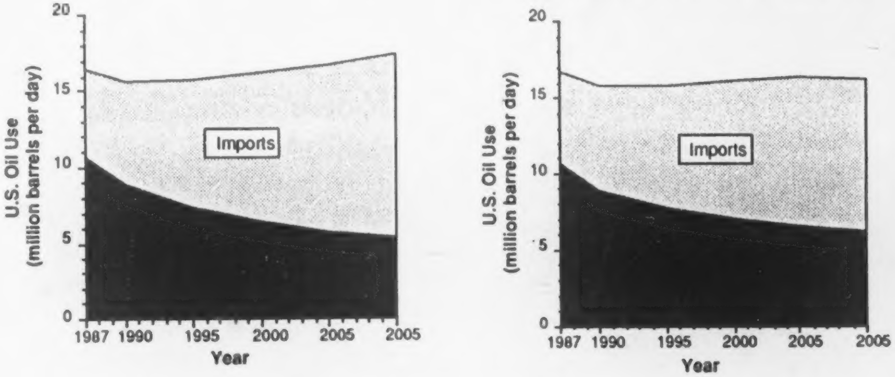
If all present policies continue, our baseline model projects that U.S. oil imports by 2010 would be approximately 13 million barrels per day—almost twice as much as ever before in history. Imports would then represent more than 71 percent of total oil consumption. Our modeling for "accelerated gas use" (which is only *one* possible alternative scenario) projected a reduction of almost 2 million barrels per day in those imports. Thus, greater emphasis on gas *can* offer greater security against possible energy disruptions in the future; but perhaps even this will not by itself allow us to breathe freely enough. About 66 percent of our oil use still would be tied to imports, and other policy initiatives probably would be needed. Yet it is hardly arguable that the nation should risk postponing some of the relatively easy and economical steps to facilitate larger use of natural gas, whose imminent contribution to oil-import reductions can be demonstrated. Time is running, even now.

U.S. May Be Vulnerable To Energy Pressures Again Before 2000

An oil glut exists today on the world market. With prices still low enough to keep our domestic drilling industry at an ebb, it may be hard for the public to focus on the fact that the international community's earlier rollercoaster rides in energy prices and energy supply could be repeated during the 1990s.

Cruel economic lessons of the 1970s have not been forgotten completely. Continued progress in energy efficiency and foreseeable fuel-substitution *is* expected to reduce oil's *percentage*-share of the U.S. energy market. We see oil falling from around 42 percent of all energy consumption now to approximately 39 percent some two decades hence—even in the baseline case. If this seems like an excruciatingly slow pace at which to "back out" the fuel that has been the basis of what once was called "The Energy Crisis," remember that oil accounted for *47* percent of the nation's energy use in 1973. Fairly heroic measures have been taken since then, notably in a consumer revolt that amazed most economists after crude oil prices briefly hovered close to $40 per barrel. The preceding section of this report gives some inkling of how imaginative and perseverant one must be to replace *additional* oil in an economy of

Two Projections of Demand for Oil in the U.S. Economy:



a. following the present course

b. with this report's assumptions about modest moves to accelerate gas supply

Anything that permitted still greater reliance on alternatives to oil (including coal, nuclear power, renewables, and improved efficiency) might lessen imports in an extension to case "b." But additional problems in taking full advantage of such sources as coal and nuclear energy would compel even higher imports.

U.S. size. Almost 6 out of every 10 barrels of oil we use go into transportation—with the greatest portion of that devoted to fueling about 160 million autos and light trucks.

Even with the "oil fraction" on its way down, our growth in population, road fleet, and GNP seems destined to force an increase in the total *amount* of petroleum products we use. For this reason, it is important to consider two other ways in which bolstering natural gas production helps to guard against oil problems we can see on the horizon:

- We have already noted that oil and gas are often found in the same geological formations. Intensified exploration for one aids discovery of the other. Part of the cuts in oil imports we project comes from the growth in domestic *oil* output that would accompany more emphasis on natural gas.

- Besides producing the "dry" gas that winds up in statistical tables and pipelines, natural gas wells and processing plants are the source of "natural gas liquids" (NGL). These can be used ultimately in place of various products that come principally from the refining of crude oil; and they already underlie about 10 percent of our national supply of such products.

Historically, a great strength of the U.S. economy has been a resource-endowment that was rich in the nation's premier fuel. At first this was wood, and then in the 19th century it switched to coal. For several generations it has been oil. Domestic producers have been much more thorough to date in tapping oil resources than they have been in taking advantage of gas, so production of the latter fuel retains some growth potential while the former will be hard pressed to hold its own. At some time in the 21st century, this nation may complete another energy transition, entering the post-hydrocarbon era. However, our study of renewable-energy technologies has led us to believe that their growth will not be rapid enough to permit them to "take over" the national energy-consumption infrastructure as early as 2010. Meanwhile, it is important to develop resource strategies that can sustain growth and protect both economic security and foreign policy interests.

One of these is already the Strategic Petroleum Reserve. The fact that it has not been called upon tends to point up its efficacy rather than to diminish the justification for its existence. Surely the 550-million-barrel-plus SPR (and its counterparts in other countries) relieved some apprehensions during the Iran-Iraq War and provided a bit more freedom of action in dealing with threats of oil cutoffs. There was also a time in the recent past when the Organization of Petroleum Exporting Countries (OPEC) was quite successful in its short-term efforts to manipulate prices by mutual agreement among suppliers. The availability of reserve crude oil that could enter the U.S. market during any period of adjustment to an emergency discourages any consortium of suppliers from trying to wield economic power again in a way that is openly hostile to our interests. The same reasoning explains why it is advantageous to develop natural gas supply as an alternative to imported oil (via the possibility of fuel-switching).

Alternatives to Oil Reduce Cartel Incentives To Squeeze Down Supply

The major danger we foresee now lies at some indeterminate point in the future when OPEC has recovered enough of the global market so that approximately 85 percent of its own oil-production capacity is being called upon to satisfy world demand. By an historical rule-of-thumb, this is when such a quasi-cartel is sufficiently emboldened to take drastic actions—raising prices sharply, withholding supply, or a combination of the two in an effort to squeeze maximum rewards for its product from customers who have little other choice.

Even in the "accelerated gas use" case, it may be almost impossible to avoid such a new confrontation forever. On a worldwide scale, our computer projections show OPEC delivering on the order of 35 million barrels of oil per day by 2010—

fully twice as much as today. But *postponing* what now appears to be inevitable is not an idle exercise. And the difference in U.S. gas consumption for *1995* between the two cases we present in this report is a hearty 1.5 tcf—the equivalent of some 750,000 barrels of oil per day. Between now and then, the policy options we assumed appear to double the prospective growth for natural gas.

As to dollar costs, this depends on whether they are viewed in a narrow or a broad context . . . in the long term or the short run. For instance, a 10-percent tax credit for exploration might directly reduce immediate government revenues by about $350 million annually. But the benefits to the whole economy (not to mention the ultimate increase in federal and state royalties for producing wells on government-controlled lands) would balance this expense within the first three years. This is covered more fully in the section of the report that begins on page 34. But the most important response to questions about the *cost* of these moves toward greater energy security is that they should, in all fairness, be balanced against other benefits as well (improved trade balances, environmental protection, and so forth). The quest for energy security is not the *only* reason for this country to swell its supply and use of natural gas; in some quarters it probably is not even the chief one.

One of the more novel ideas that emerged during our study was a proposal that the nation's program for a Strategic Petroleum Reserve be broadened to include the largely decentralized storage of natural gas as well. Because demand for gas is highly seasonal, the dollar-wise impulse to utilize pipeline capacity to its fullest has led to the creation of a vast number of underground reservoirs—usually quite near consumption centers, but invisible to customers. Given the substitutability of natural gas for oil, we questioned whether it might not be cost-effective for the Department of Energy to lease such space and fill it with purchased gas as an additional buffer against price shocks or supply problems in oil.

Certainly this is one concept on which instant consensus within the gas industry itself is impossible. Producers, transporters, and distributors of gas have differing viewpoints. Like the prickly question of how to settle old "take-or-pay" contracts, the possibility of an SGR was not addressed specifically in our modeling. Yet we raise the notion in this report because we believe it is worth being subjected to further critical analysis.

How much can natural gas do for environmental quality?

Natural gas *can* do even more for the cause of clean air in this country than some of its proponents say it will. It depends a lot on how conscious we are as a nation of how various types of atmospheric pollution take place.

In coming to grips with the problems of airborne pollutants, there has been too much preoccupation with "percentages" or "tonnages of emission reductions" (often "determined" theoretically), as distinguished from real *results in improved air quality*. Sometimes there has even been a stubborn, counterproductive insistence on specifying the *way* emissions should be curbed.

The nation would be better served if performance standards replaced attempts to dictate compliance technology in environmental-protection efforts associated with the production and use of energy. We assumed such a policy orientation in our model—which paves the way for more use of natural gas and, incidentally, an even greater-than-proportional set of benefits to the environment. We also resolved to dig deeper than the obligatory (but essentially misleading) sort of observation that "the use of so-and-so-much natural gas will reduce the atmospheric burden of sulfur dioxide by so-many tons, as compared with Fuel X."

Most people realize that natural gas is a clean-burning energy source. A table on the following page shows abstractly how it compares with typical samples of coal and oil. This alone is sufficient to show that environmental improvements will hang in part upon whether gas is being substituted for oil or for coal. However, there are other variables as well. Timing and placement of the fuel-substitutions are equally important in the long run.

Environmental Value Depends On Which Fuels Are Replaced, When, Where, and How

Professors James A. Fay and Dan S. Golomb, of the Massachusetts Institute of Technology, have produced an excellent analysis, "Natural Gas and the Environment: Benefits for Air Quality," which is one of several reference documents being circulated in conjunction with this summary report for those who are interested in more detail. Even to treat the topic in brief, however, it seems desirable here to explain five general types of environmental effect that arise in part from burning fuels:

- **Acid Deposition**—which goes beyond the familiar shorthand term ("acid rain") to include snow, hail, dew, and even dry deposits of acids that may be formed in the air from the interaction of sulfur and nitrogen oxide emissions with atmospheric oxidants (including ozone).
- **Ozone at Ground-Level**—which has nothing to do with the potentially dangerous lack of ozone in the upper atmosphere, but

Comparative Pollution From Uncontrolled Burning of Gas, Oil, and Coal
(using emissions from gas as the standard)

Pollutant	*Gas*	*Oil*	*Coal*
Sulfur dioxide (SO_2)	1	1000-3000	3000-8000
Nitrogen oxides (NO_x)	1	2	4.5
Small particles	1	20	250
Carbon monoxide	1	1.5	1.5
Carbon dioxide	1	1.25	1.7
Reactive hydrocarbons	(There are virtually no emissions of this type from natural gas. Emission from oil is about twice that from coal.)		

instead is a problem because *concentrations* of this toxic variant of ordinary oxygen can harm plants and cause respiratory diseases when breathed. Ozone is one of the ingredients of smog. It builds up as sunshine works on nitrogen oxides in the presence of reactive carbon compounds (such as gasoline fumes and partially burned gasoline).

- **Carbon monoxide**—a toxic product of incomplete combustion, especially from vehicles. This gas is one of the precursors of ozone.
- **Particulates**—the tiny bits of matter suspended in the air (including soot, fine ash, and assorted kinds of dust and dirt) that turn clear skies into haze and are linked to various health problems.
- The **"Greenhouse Effect"**—a long-range phenomenon of slowly rising temperatures worldwide under a blanket of some pollutants (based partly on a general increase in fuel-combustion of all kinds) that has attracted broad attention recently.

In some cases the pollution effects are not limited to the immediate vicinity of emissions, and in many cases the adverse effects that have been observed come from more than one pollutant.

"Acid rain" is derived largely from sulfur dioxide (SO_2) and nitrogen oxides (NO_x)—especially in *hot, sun ny weather* if oxidants are abundant. In eastern North America, there is a sharp peak in atmospheric acid generation between June and August. Ozone forms when NO_x and hydrocarbons (HC) react together chemically in *sunlight*—particularly on warm, breezeless days. And most of the visibility-blocking haze from particulates also occurs in *summer*.

Perhaps half of the gas-accumulations that give rise to fears about the greenhouse effect consist of carbon dioxide. To produce a given amount of heat, natural gas emits almost 50 percent less of this compound than coal and 20 to 30 percent less than oil. Furthermore, the higher conversion efficiency of gas-fueled combined-cycle turbines promises an additional advantage when CO_2 emissions are related to output of electricity. However, there is a fair body of scientific opinion that "global warming" could regulate itself in various ways; and the emissions that tend to promote it are not all tied to energy production and use. This may not be as strong or independent a talking point on behalf of gas use as some have assumed.

It is obvious that extra substitution of natural gas for other fuels during the summer months would go most directly to solving many pollution problems that exist. To give a concrete example, a typical 500-megawatt oil-fired powerplant releases some 70,000 tons of sulfur dioxide annually. Replacing oil with gas *for the six months between April and September* (when gas prices drop in many regions anyway) would cut the *annual* output of SO_2 to 35,000 tons; but, because acid formation normally speeds up during those months, the *effect* would be the same as if it had been cut to only about 17,500 tons year-round.

Fortunately, this approach would dovetail with the traditional seasonal lull in U.S. consumption of gas (which is still used in the residential and commercial sectors primarily for heating). The pipeline network nationwide is less than four-fifths full of gas during summers now—with regional rates of capacity utilization ranging from 51 to 93 percent.

Fay, Golomb, and others have also pointed out another sort of environmental bonus from selective use of gas. Some equipment permits the burning of gas simultaneously with either coal or oil. In such "co-firing," the combustion with gas actually "scavenges" some pollutants that result from burning the other fuel. Some tests showed that substituting gas for only 20 percent of the heat value of coal or oil in an installation reduced NO_x emissions by 60 percent.

In the case of generating plants, replacing coal or oil with natural gas in actual practice appears to be able to reduce the production of sulfur dioxide in almost direct proportion to the percentage of gas used. On balance, replacing half of the heat value of coal that contains 1.2 percent sulfur with gas will lower SO_2 emissions from 2.5 pounds per million Btu's to about 1.2—which happens to be the rate targeted in most "acid rain bills."

Selective Substitution Of Natural Gas Offers The Maximum Benefits

Pollution control is a complex process. Its effectiveness usually depends on local circumstances, and its economic rationality almost always does.

A recent examination of several hundred diverse eastern powerplants came to the conclusion that the very same reduction in acid rain that might result from ordering all of them to install flue-gas desulfurization equipment ("scrubbers") would be achieved—*at less cost*—by switching from the present fuel (either coal or oil) to gas during the summer half-year.

Lest this encourage a move to *order* that approach universally, it should be added hastily that gas-substitution is not always the best answer either. First, the costs of capital investment, fuel, and plant operation must be evaluated for each of many possible options. The older a facility is, the less worthwhile it is to install the prodigiously expensive scrubbers—which are also costly to operate (because of their complexity, the net-power-loss they involve, and the sludgy wastes that may be generated by hundreds of thousands of tons at a single site). But it also costs some money to convert an oil-fired or a coal-burning plant to make it compatible with natural gas—whether this is done by altering the boilers in place or through providing new side-by-side equipment. Adapting the same system to use *either* of two fuels (or both at once) generally lowers heat-conversion efficiency too—although performance often improves when natural gas replaces either coal or oil, while maintenance becomes easier.

Requiring Air Quality Results Is Wiser Than Telling How to Comply

Trade-offs among all the competing technologies that might produce acceptable results in air quality (whatever standards are to be maintained) can best be determined by the operator involved. This also explains why the "bubble concept" and trading of "emission credits" make sense when compliance with environmental standards is being monitored. Under the former, an industrial or energy-producing complex is judged on the basis of the total emissions it adds to an area—rather than by evaluating each of its components individually. With "credit trading," an entire installation that gains "points" by reducing emissions more sharply than regulations require is permitted to sell certain emission "rights" to a nearby operation when this might enable the second owner to adopt a cost-saving practice that otherwise would be just beyond the stipulated emission limits.

Without question, both principles could be extended to environmental improvements that come from *selective* switches to natural gas. Both promote competition in finding the best *overall* solution to inevitable pollution dilemmas in the future. By contrast, the "conventional wisdom" that underlies energy-use projections like the one we created in this study as a "base case" are blind to reality: The *baseline of emissions* is fated to rise so long as more energy must be produced and consumed in any way.

Stationary sources of pollution (such as powerplants, factories, and other buildings) are not the only contributors to acid rain, ozone buildup, and dirty air. According to the interim report of the National Acid Precipitation Assessment Program issued earlier this year, for instance, more than one-third of the NO_x emissions in this country can be traced to highway vehicles—with other forms of transportation adding another 10 percent. Here once again, a generalized comparison of fuel emissions such as appears in the table on page 30 does not tell the whole story. The latest information about the conversion of gasoline- or diesel-fueled vehicles to compressed natural gas shows that this can *slash* emissions of carbon monoxide and reactive hydrocarbons. Even if widespread use of natural gas vehicles (NGVs) were limited mainly to *fleets* in metropolitan areas, it would at least give many cities a fighting chance to comply with national ozone standards. As things stand now, Los Angeles fails to meet requirements on ozone-limitation almost daily throughout each summer.

In all, as of June 1988, 341 U.S. counties failed to meet requirements of the Clean Air Act for ozone. Many fell short of compliance in regard to one or more of the other major pollutants in question too: 129 for particulates, 127 for carbon monoxide, 49 for SO_2, and 4 for NO_x. More urban areas will soon fall below various legislated lines unless significant new measures are undertaken. *Something* must be *done!*

Methanol (derived from natural gas) is another vehicular fuel that would reduce some emissions. For instance, its use gives off less NO_x than gasoline does; and with certain engine adjustments it also cuts carbon monoxide. As explained earlier, however, we limited the single composite "model" we present here to CNG conversion only.

What are the implications for budget, overall growth, and international affairs?

Taken as a Whole The Program Is Affordable —Even in Frugal Times

The first question when any fresh policy surfaces in Washington this year is: "What effect would it have on the budget deficit?" Because we considered this constantly as we built and polished the assumptions for the accelerated-gas-use model that wound up being described in this report, we are able to respond with confidence: "Little net difference in the short run, but with budgetary benefits increasing steadily in future years."

Perhaps the secret to this welcome finding of fiscal responsibility in WEFA's searching computer analysis is that the situation we postulate is not a "program" in the same sense as an effort to accomplish a specific mission in space, or to develop a broad array of synthetic fuels, or (all by itself) to chop oil imports to an absolute minimum. Instead, it is a composite of many, small governmental handholds and nudges that use the leverage of private-sector motivations to progress incrementally toward certain goals that everybody agrees we must seek—cleaner air, less dependence on unreliable oil supplies, a better trade balance, a healthy employment outlook at the national and regional levels, and so on.

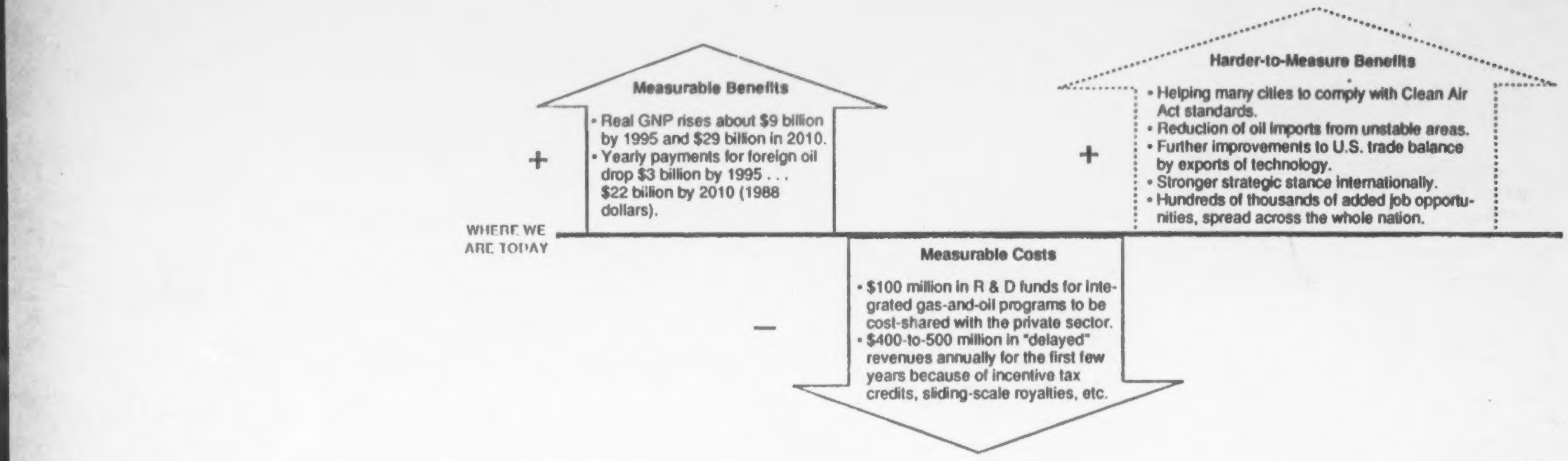
The model is comprehensive enough to integrate any results that can be expressed unequivocally in dollars and cents. Obviously there are some pluses and some minuses, as represented graphically on the opposite page. One implicit factor in the equation, however, consists of benefits whose cash value is real but imprecisely perceived. These are listed in the arrow on the right-hand side.

For instance, if the needed improvements in energy security we enumerated earlier in this report are not achieved by producing and using more natural gas, it is a cinch that their achievement by other means will add costs somewhere else in the budget. The same goes for the nationwide commitment to bring air quality into compliance with the law.

The largest single direct annual *cost* among the policy options appears to be for tax credits on exploratory and redevelopment drilling. But within two years after enactment of the tax credit the WEFA model indicates that the federal budget deficit would actually be reduced by almost $1.4 billion because of revenues collected on business activity and wage payments that would not have occurred otherwise. Our analysis on the basis of output-per-well indicates that each additional redevelopment well, involving some $20,000 in tax credit, would make about a billion cubic feet of additional gas available for production over a 10-15 year period. Such results would clearly stimulate the industry to make continuing investments in the process of recovering "bonus

Generalized Cost/Benefit Balance of the "Accelerated-Gas-Use Case"

(all dollar costs are in 1988 equivalents)


Measurable Benefits
+
• Real GNP rises about $9 billion by 1995 and $29 billion in 2010.
• Yearly payments for foreign oil drop $3 billion by 1995 . . . $22 billion by 2010 (1988 dollars).
WHERE WE ARE TODAY
Harder-to-Measure Benefits
+
• Helping many cities to comply with Clean Air Act standards.
• Reduction of oil imports from unstable areas.
• Further improvements to U.S. trade balance by exports of technology.
• Stronger strategic stance internationally.
• Hundreds of thousands of added job opportunities, spread across the whole nation.
Measurable Costs
–
• $100 million in R & D funds for integrated gas-and-oil programs to be cost-shared with the private sector.
• $400-to-500 million in "delayed" revenues annually for the first few years because of incentive tax credits, sliding-scale royalties, etc.

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gas" that had been bypassed in older fields because of less complete knowledge earlier about reservoir patterns.

Thus, although a 10-percent tax credit for exploration drilling would be portrayed as an immediate cost to the Treasury of $350 million through lowered revenues, the program should actually *enhance* federal revenues in a very short time. Our soundings of the industry confirm the model results, but lead us to doubt that much investment will be made at all on additional exploration and redevelopment in the immediate future (while energy prices remain very low and the demand for gas is "soft") without some such stimulus. Aside from additional royalties the government would receive in any case where such "new-found" gas is produced from federally controlled well sites, an offset on the positive side would come from increased economic activity throughout the surrounding region. Because many areas suitable for redevelopment drilling are now depressed, the social benefits as well as the economic ones (including greater tax revenue from job-income and supporting business) should be considered when evaluating the proposal.

It ought to be kept in mind always that there is a symbiotic relationship between gas supply and gas demand . . . and among many elements of the policy options in this or any other alternative scenario. Eliminating a single piece of the picture (such as the redevelopment credit) might not destroy the entire image, but it would stand a good chance of distorting it unless another initiative with the same net influence were substituted.

In "big picture" terms, this set of policy assumptions yields strong positive results. Gross national product is bumped upward slightly—from $6,855 billion to $6,884 billion (in current dollars) by 2010. The U.S. trade deficit is improved too, even in the shorter run, because of lower oil imports—**with the differential amounting to $1.4 billion in 1995 (in current dollars), and rising to nearly $24 billion by 2010.** By then, the lowering of U.S. demand for imported oil by about 2 million barrels per day would produce some reduction in the world oil price too, providing some economic benefit; but we estimate that this would only amount to pennies per barrel.

The rise in GNP we project is a result of many factors and touches many parts of the economy. Producing additional steel for an expanded pipeline network, as well as "pipe" and "tubulars" for the oil and gas wells themselves, creates jobs in what has sadly been dubbed the "Rust Belt." Expanding new gas fields where the industry might otherwise be moribund adds work in Appalachia. (Incidentally, the steady rise projected in demand for coal—even though at a lower rate than in the baseline case—shows clearly that this companion energy industry is also likely to have an expanding rather than a contracting payroll overall.) In net total, the additional economic growth was projected to **add some 374,000 jobs by 2010.**

Productivity and competitiveness are other vital criteria these days, and the more efficient development of U.S. resources in the "accelerated-gas-use case" is among its pluses. It has been estimated that our technology in extracting natural gas from the earth improves by perhaps 2 to 3 percent per year (although this change is masked by larger fluctuations in drilling costs). Thus, even in the base case, we projected that this country would be able to lower its current-reserves-to-current-production (R/P) ratio from 10.2 to 8.2 by 2010. With additional R & D and the entire new environment for natural gas, analysts involved in this study suggest that this ratio could approach 7.0 in the United States, thereby improving production economies.

World reserves of natural gas represent more than 3,600 quads, but less than 2 percent of that base is now being produced annually. Besides the U.S., the six countries that are known to have natural gas reserves of 100 quads or more each are Canada, Iran, Norway, Qatar, Saudi Arabia, and the Soviet Union.

Exports of new U.S. technology for geoscience and the extraction of hydrocarbon fuels also can help in closing our trade deficit to some extent, but worldwide growth for natural gas promises benefits on its own to this country.

A multinational tilt from oil toward gas would make the global energy market more stable. World reserves of natural gas are comparable to those of oil, but they are dispersed more widely. About 58 percent of all oil reserves are concentrated in the Middle East, but only 26 percent of the gas reserves lie there. Industrialized nations (the major users of gas, now and in the foreseeable future) control only 16 percent of those oil reserves but 57 percent of the gas reserves.

Nor is this a case of boosting the "haves" against the "have nots." Many populous, less-developed countries (among them Mexico, Venezuela, Argentina, Pakistan, Thailand, Nigeria, Indonesia, and China) have large natural gas resources that can be tapped more assiduously to satisfy their growing domestic needs for energy. Their broader use of low-polluting fuel is especially desirable in the face of environmental problems that can also be expected to increase as their transportation networks proliferate and industries connected to higher living standards expand.

Japan is a special case among nations. It has virtually no indigenous energy sources, and it already has contracts to bring in large amounts of liquefied natural gas from Indonesia, Alaska, Brunei, Australia, and Abu Dhabi. By the turn of the century it might add the Soviet Union and Nigeria to this list, and Japan could also negotiate with China for natural gas supplies at some future date. (The U.S.S.R., which itself consumes about one-third of all the natural gas produced in the world each year, contains approximately 40 percent of the earth's reserves.) Japan is concerned about air pollution and might determine to put great stress on gas as a transportation fuel, as well as a heat source in generating electricity.

Western Europe is scheduled to become a closer economic unit in the early 1990s; and, considered as such, it has 220 quads of natural gas reserves—with considerable potential from the Norwegian fields in the North Sea. At present, Western Europe imports gas from the U.S.S.R. and (via a pipeline under the Mediterranean) from Algeria. LNG imports from Nigeria may also begin to serve some parts of Europe within a decade or so, but its own gas production could be encouraged further. We believe that gas use there could grow safely by about the same rate as the one we projected in this report's "accelerated" case.

U.S. Leadership Can Help Develop Wholesome Role For Natural Gas Worldwide

The "new environment" for natural gas is upon us—here and throughout the world. In this country, producers, transporters, distributors, and consumers have finally begun to look for mutual interests rather than to focus on what divides them. A new President-elect and a Congress controlled by the opposing party at least seem to have common goals. In mid-1989, a ministerial meeting of the International Energy Agency (IEA) could well begin to explore cooperative efforts to grasp the environmental, security, and economic advantages natural gas offers. The time is ripe to put priorities and policies in order.

How This Study Was Conducted

When policy goals are separated from real-world *possibilities*, the results may be frustration and disappointment. Industry and government filing cabinets are replete with "wish lists" that never become more than that.

The principals of Washington Policy and Analysis sensed a formidable and rapidly growing national consensus on the multi-faceted promise of natural gas for the rest of this century and into the next. But they recognized the disturbing reality that the fuel's supply and demand in this country were both still being projected at a level that meant major potential benefits in environmental protection and greater energy security might not be realized.

A country this size does not usually change energy trends quickly except in response to a trauma, so we knew it made sense analytically to try to push our vision as far ahead as we could with rigor. The WEFA Group (newly formed in a merger of Wharton Economic Forecasting Associates and Chase Econometrics) had excellent tools to do the job and the ability to focus them simultaneously on a single task: a) its World Forecasting Service (which would be essential because of interrelationships between the United States and world markets; b) its Long-Term U.S. Macroeconomic Model; c) its gas and oil supply model; and d) its model to coordinate supply and demand for all U.S. energy sources.

We formulated conceptually the questions that had to be answered by integrated computer simulations for the years between now and 2010, then authorized WEFA to begin. Our baseline followed the reference case published by that group in July 1988. To evaluate the practical possibilities of putting greater emphasis on gas, we injected and tested a series of assumptions in components of the model that were controllable variables. We were open to change, but also kept our eyes open to federal budgetary caution as well as to real political limitations and to the recent history of tensions among various segments of the natural gas industry itself. We tried to postulate an alternative situation that would be at least a framework for future discussion and eventual consensus. For instance:

On the supply side, we

- incorporated assumptions about a broader gas reserve base that grew out of a Department of Energy study published in the spring of 1988 (which was reinforced independently by the latest industry estimates);
- weighed the possible effects of federal R & D support that targeted, for example, the geosciences relevant to hydrocarbon deposits (a slight shift in policy emphasis that would probably be reflected in changes to the R/P ratio for natural gas—total reserves divided by annual production);
- gauged the results of tax incentives for exploration and production rather directly—because these modify returns on investment all along the line;
- considered the great progress made over the past eight years to free up energy trade on both sides of the border between the United States and Canada—even apart from the U.S.-Canadian Free Trade Agreement (whose aim in this instance was mainly to consolidate formally an already healthy set of working arrangements);

- incorporated production of "unconventional" supplies of gas from coal seams, coproduction, and Devonian shale that would be available as a result of technological improvements based on research efforts; and
- added the potential for more development of gas on the North Slope of Alaska.

These assumptions, coupled with our price assumptions, provided us with an upper ceiling for available gas supply. Professor Robert Finley, of the University of Texas at Austin, reviewed the initial gas supply profiles that were produced to ensure consistency between the econometric results and geologic reality.

On the demand side, we

- adopted the basic WEFA projections for GNP and oil price;
- adjusted exploration and production levels for both gas and oil to reflect increased drilling, allowing the WEFA model to calculate the full effects on U.S. economic activity;
- developed assumptions about the industrial penetration of advances in end-use technology, in consultation with Professor Robert Williams, of Princeton; and
- incorporated assumptions regarding "least-cost" strategies for reducing emissions to meet air quality standards (with the assistance of Professors James Fay and Dan Golomb of MIT, and David Bardin).

We compared baseline outputs with runs on the "accelerated-gas-use" scenario and noted the resulting differences in fuel-mix and trade balance over the projected time span. Then we examined the variations in order to estimate the environmental implications.

Finally, the WEFA Long-Term U.S. Macroeconomic Model incorporated all the changes in the energy sectors and the trade sectors of the economy, as well as the fiscal policy aspects of the "new gas environment," to generate the impacts that might be anticipated on the economy as a whole (GNP, employment, deficits, and so on). The results were compared with the baseline to measure the effects of the changes.

Technical Papers Associated With This Study

Natural Gas: Resources and Producibility. William L. Fisher, Bureau of Economic Geology, University of Texas at Austin.

Natural Gas and the Environment: Benefits for Air Quality. James A. Fay and Dan S. Golomb, Massachusetts Institute of Technology.

Advanced Gas Turbines for Power Generation. Robert H. Williams, Center for Energy and Environmental Studies, Princeton University.

The Role of Natural Gas in Energy and Environmental Policy. David J. Bardin, Arent, Fox, Kintner, Plotkin & Kahn, Washington, D.C.

Natural Gas: A Strategic Resource for the Future. A Tabular Comparison of the Baseline and "Accelerated-Gas-Use" Cases Modeled by the WEFA Group.

Two Possible Futures for U.S. Gas Supply

Baseline Case—The Present Course (tcf)

	1990	*1995*	*2000*	*2005*	*2010*
Lower-48 conventional gas	15.8	15.8	15.1	14.9	15.5
Associated	3.3	3.1	2.8	2.6	2.5
Nonassociated	12.5	12.7	12.3	12.3	13.0
Imports	1.4	2.1	3.2	3.4	3.3
Canada	1.3	1.6	2.3	2.5	2.4
Mexico	0	0	0.1	0.1	0.1
LNG	0.1	0.5	0.8	0.8	0.8
Unconventional	0	0	0	0	0
Alaska	0	0	0	0	0
Total tcf	17.2	17.9	18.3	18.3	18.8
Total quads	17.7	18.5	18.9	18.9	19.4

Alternative Case—Recognizing a "New Gas Environment" (tcf)

	1990	*1995*	*2000*	*2005*	*2010*
Lower-48 conventional gas	16.1	16.7	17.7	18.5	18.1
Associated	3.3	3.1	2.8	2.8	2.9
Nonassociated	12.8	13.6	14.9	15.7	15.2
Imports (total)	1.5	2.5	3.7	3.8	3.8
Canada	1.4	1.5	2.4	2.5	2.5
Mexico	0.0	0.3	0.5	0.5	0.5
LNG	0.1	0.7	0.8	0.8	0.8
Unconventional	0.1	0.2	0.3	0.8	1.0
Alaska	0	0	0	0	1.2
Total tcf	17.7	19.4	21.7	23.1	24.1
Total quads	18.2	20.0	22.4	23.8	24.8

A Research Report
of WASHINGTON POLICY AND ANALYSIS
A MILLER & CHEVALIER CONSULTING GROUP

If the United States is to take full advantage of natural gas as a strategic resource for the future, here is a sample of what might be done in 1989:

1. Expand federal funding for research and development on the geoscience that underlies natural gas production, especially in regard to enhanced gas and oil recovery. To limit federal outlays (and to make sure that the results are put to use broadly and promptly), this could be done with industrywide support through the Gas Research Institute or through cooperative ventures linking government, industry, and universities.

2. Expand federal funding and other incentives for R & D linked to gas-use technologies—including programs designed specifically to promote the commercialization and economical penetration of the market by new combustion turbines for the generation of electricity, cooling by gas, natural-gas vehicles, and the selective use of "co-firing" with gas and other fuels.

3. Identify the onshore and offshore federal lands that are attractive targets for environmentally sensitive exploration and production, and make them more accessible to the private sector.

4. Enact a program of limited tax incentives to encourage domestic exploration for gas and oil and redevelopment drilling in older fields.

5. To take full advantage of new promise from geoscientific knowledge about hydrocarbon deposits that have been bypassed or untapped, institute a 10-percent tax credit for redevelopment drilling.

6. To clarify the ground rules for most future investment, enact complete decontrol of wellhead prices for all gas.

7. Promote a "least-cost" strategy for reducing the emissions of pollutants from energy's production and use, by implementing environmental regulations that are based on performance (for example, by favoring such low-cost options as trading emission "credits," burning gas in conjunction with other fuels, and having compliance monitored in terms of areawide "bubbles" rather than individual facilities).

8. In areas where environmental standards are not being attained, make sure that federal funds provided to local government for vehicles are used exclusively for low-polluting equipment.

9. Use all environmentally responsible procedures at the federal government's command to expedite the licensing of new capacity for pipeline delivery of gas to the Northeast.

This is no "magic formula"; but it is at least a framework for executive and legislative discussion, in that it addresses both supply and demand. Concentrating on one without the other simply does not promise to change the outlook. A new attitude toward natural gas is emerging—in the U.S. and worldwide. But it will be thwarted by either a "business-as-usual" or a piecemeal approach.

NGSA MEMBER COMPANY SURVEY:

NATURAL GAS SALES & PRODUCTIVE CAPACITY

AS OF JANUARY 1, 1989

Natural Gas Supply Association
1129 20th Street, N.W.
Suite 300
Washington, D.C. 20036

September 26, 1989

NGSA MEMBER COMPANY SURVEY:
NATURAL GAS SALES & PRODUCTIVE CAPACITY
AS OF JANUARY 1, 1989

EXECUTIVE SUMMARY

The 1989 NGSA natural gas sales and productive capacity survey reveals the following trends:

- In the U.S. lower-48 states, current wellhead gas productive capacity appears to be sufficient to meet recently demonstrated levels of gas demands. This conclusion is based on the relatively low December 1988 capacity factor of 82.2 percent, and the moderate 3.6 percentage point increase in capacity factors between December 1987 and December 1988.

- Based on the financial reports of the survey respondents, about 50 percent of the depleted productive capacity was replaced during 1988. The analytical results also suggest that a direct linkage exists between gas capacity replacement and gas reserve replacement from extensions and discoveries. From a different perspective, the analysis implies that gas reserve revisions might have little impact on current deliverability.

- Of the five major supply regions in the survey (i.e., Offshore Gulf, Onshore Gulf, Permian & San Juan Basins, Anadarko, and Rocky Mountain), the Onshore Gulf region appears to have the smallest December 1988 capacity surplus (at a 91.8% capacity factor) and the most rapid rate of decline in the capacity surplus. The Permian & San Juan region appears to be the second most constrained supply region with a December 1988 capacity factor of 83.6 percent. Conversely, the Offshore Gulf region appears to be the least constrained by wellhead gas capacity, given its December 1988 capacity factor of 80.7 percent.

BACKGROUND

In March of this year, for the second consecutive year, the NGSA surveyed its member companies about their regional natural gas sales and productive capacity in the lower-48 states. This information, in turn, can be used to estimate the size and the rate of change in the size of the natural gas surplus.

A list of the twenty-four companies which responded to the 1989 survey is provided in Schedule 1 of Appendix A. The eight lower-48 survey regions are defined in Schedule 2 of Appendix A.

This year's survey questions and format were significantly changed from the prior survey. The 1989 survey reports not only well capacity and sales for the January 1, 1989 timeframe, but it also reports the same information for the January 1, 1988 period. This permits an analysis of year-to-year trends on a consistent basis. Moreover, the survey asks for information for eight regions in the lower-48 states. These regions conform more to the geological boundaries associated with oil and gas producing basins than to the state boundaries. Thus, the new survey provides a more detailed examination of the trends within gas producing basins. Finally, the survey asked respondents to state whether their survey responses were answered on a "dry" gas or "wet" gas basis. This permitted the translation of "wet" survey numbers into "dry" survey numbers, which in turn, provides a common basis for working with the aggregate numbers tabulated from the individual survey responses.

METHODOLOGY

The NGSA survey format and aggregate results are provided in Appendix A, Schedule 3.

Respondents were asked to fill out the survey forms on an operating basis rather than on an ownership basis. The operator of a gas field should have a better knowledge of the field's operating characteristics and potential capacity than the non-operator owners. Conducting the survey on an operating basis alone also eliminated the possibility that co-owners of a gas field would report on the same field more than once, thereby causing a double counting problem for the survey.

In order to put the survey results on as comparable a basis as possible, surveys which reported gas capacity and sales on a "wet" gas basis were converted to a "dry" basis using the conversion ratios provided in Appendix B Schedule 1. The conversion ratio between "wet" gas and "dry" gas was developed using the natural gas reserve data reported by the Energy Information Administration in its report entitled: "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1987 Annual Report". The conversion ratio equals a region's total gas reserves expressed on a dry basis divided by the region's total gas reserves expressed on a wet basis. Multiplying this conversion factor by the "wet" gas volumes provides the estimated "dry" gas volumes. The survey results on a "dry" basis are presented in Appendix A in Schedule 3.

SURVEY COVERAGE OF LOWER-48 NATURAL GAS PRODUCTION

The survey respondents were responsible for approximately 46.7 percent of December 1987 dry gas production, and 47.1 percent of December 1988 dry gas production. See Appendix C, Schedule 1 for the coverage calculations.

The regional gas production capacity for the survey respondents relative to the regional capacity on the entire industry is provided in Appendix C, Schedule 2. The Offshore Gulf region is particularly over-represented in the survey results. The survey respondents report that about 42 percent of their December 1988 production came from the Offshore Gulf region compared to 30 percent for gas producers as a whole. The survey's over-representation of the Offshore Gulf region means that the other regions were under-represented relative to the entire gas production industry. In particular, the Onshore Gulf, Anadarko, Appalachia, & Pacific regions were all significantly under-represented in the survey results. The regional production shares for the survey and the industry as a whole were almost identical for the Permian & San Juan Basins, North Central, and Rocky Mountain regions.

AGGREGATE RESULTS FOR THE U.S. LOWER-48 STATES

An Estimate Of 1988 Gas Capacity Replacement

A gas capacity replacement rate can be estimated for the survey respondents from the gas production and reserve information contained in the respondents' annual reports and SEC 10-Ks. Even though the annual report information provides a useful perspective on annual production and reserve changes, it is not completely consistent with the survey results. First, the annual report information is not fully comparable to the survey's because the survey was conducted on an gross operator basis while the financial information is reported on a net ownership basis. Second, the fiscal year of some of the respondents does not conform to the calendar year. Finally, natural gas reserve data was not available for two small propriety firms. Yet, even with these drawbacks, a comparison of the change in gas reserves to the change in gas capacity is instructive.

The gas reserve depletion rate for the survey respondents was calculated by dividing 1988 gas production by the average 1988 proved, developed gas reserves. Proved, developed reserve data were used in the depletion rate calculation (instead of the proved, developed and undeveloped gas reserves) because gas well capacity is more directly tied to developed reserves. Moreover, this calculation assumes that wellhead deliverability declines at a rate equal to the rate of gas reserve depletion.[1] Based on this analytical perspective, the survey respondents' gas reserves and wellhead capacity declined by about 10.5 percent per year during 1988, as is shown on Schedule 2 of Appendix D.

This estimated rate of gas reserve depletion can then be compared to the survey's reported change in gas well capacity as a means of estimating the rate of gas capacity replacement. For example, if new gas well drilling and production enhancements completely replaced field depletion effects, then the percentage change in gas well capacity would equal zero. Similarly, if gas well capacity declined at a rate equal to the rate of reserve depletion (i.e., the rate of gas field depletion), then presumably no capacity replacement has occurred. In general, the percentage of capacity replacement equals one (1) minus the quantity of the change in gas well capacity divided by the respondents gas reserve depletion rate (i.e., [1 - [change in capacity/change in gas reserves]]).

The change in gas well capacity can be calculated on both a connected capacity basis and a total capacity basis (i.e., connected plus unconnected capacity). The unconnected well capacity can either be excluded or included in the capacity replacement calculation because some proportion of the total unconnected capacity includes productive gas wells which cannot deliver their full capacity of gas to the market because of pipeline bottlenecks. On the other hand, the unconnected capacity also includes situations wherein the gas can not be currently produced, but can be made available to the market within a one year timeframe. Thus, a range for the rate of gas capacity replacement is bracketed by the inclusion and exclusion of the unconnected gas well capacity in the calculation. As shown in Table 1, connected well capacity declined by 5.0 percent during 1988, and total capacity declined by 5.7 percent. Thus, the estimate for the gas wellhead capacity replacement rate ranges from a low of 48 percent replacement to a high of 54 percent replacement.

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[1] This assumption is a more correct representation of reality when production is not demand constrained, and less correct during a supply surplus when gas wells are not operating at full capacity.

Gas Capacity Replacement And Survey Respondent Gas Reserve Changes

If gas well capacity is partly a function of the size of gas reserves then changes in gas reserves might be correlated with changes in gas capacity. An examination of Appendix D Schedule 1, shows that the survey respondents replaced about 52 percent of their production through field discoveries and extensions. About 93 percent of production was replaced through reserve revisions, field discoveries and extensions. The estimated capacity replacement rate ranges between 48 and 54 percent and closely coincides with the 52 percent reserve replacement rate of production brought about by field discoveries and extensions. This suggests that the percentage replacement of reserves through field extensions and discoveries might be a good surrogate measure for the percentage replacement of gas wellhead productive capacity.

Reserve replacement through extensions and discoveries can occur only if wells are physically drilled. The drilling of gas wells should incrementally add to gas wellhead productive capacity. Yet positive reserve revisions do not always require additional well drilling which would enhance existing wellhead capacity. Upward reserve revisions can occur for a number of non-drilling reasons, such as:

1) An upward revision can result when a gas field's production declines at a rate less than was originally anticipated by both the geologists and reservoir engineers. Higher sustained rates of production usually indicate a larger reservoir than what was originally booked; hence, the upward reserve revision. (Conversely, reserves can be revised downward if production falls off at a rate faster than was originally anticipated.)

2) Higher sustained wellhead gas prices can also result in positive reserve revisions. Higher wellhead gas prices permit the operator to spend more in operating improvements, such as, additional well workovers or by adding field compression to remove gas from nearly depleted gas fields.

3) The introduction and use of new technologies, such as the co-production of natural gas and water, permit higher recovery rates irrespective of the prevailing wellhead gas price.

Of course, there will be other instances where a reserve revision is associated with higher deliverability rates. For example, well reworking can result in both a higher deliverability rate and a revision of the field's ultimately recoverable gas reserve.

The hypothesis that reserve replacement from extensions and discoveries is indicative of capacity replacement is, at best, tentatively confirmed by the current survey results. Future surveys will either fully confirm or fully refute this hypothesis.

Gas Wellhead Capacity Factors And Surplus Levels

A. December 1987 and 1988 Capacity Factors And Surplus Levels

Table 2 provides an estimate of connected well capacity factors for December 1987 and 1988.[2] As shown in Table 2, December capacity factors increased by 3.6 percentage points, going from 78.6 percent in 1987 to 82.2 percent in 1988. Even though December gas sales dropped by 0.7 percent between December of 1987 through December of 1988, the primary cause for the increasing lower-48 capacity factor is the 5 percent drop in connected gas well capacity.

December capacity surplus estimates are provided in Table 3. Again, the drop in connected well capacity amounting to 1,440 MMcf/day is partly offset by the 148 MMcf/day drop in December sales. Thus, the December surplus shrunk by 1,292 MMcf/day going from a December 1987 surplus of 6,138 down to 4,846 MMcf/day in December of 1988.

As is shown in Tables 2 & 3, some regions of the country are operating at higher capacity factors while their surplus is diminishing at a rate faster than the total lower-48 (e.g., Onshore Gulf Coast), implying that capacity and sales might come into balance in some regions before the nation as a whole comes into balance.

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[2] Using December gas production figures as a measure for peak winter production is appropriate because December and January are traditionally the highest production months. Preliminary Energy Information Administration data indicate that December 1987 & January 1988 production levels were virtually identical while December 1988 production exceeded January 1989 production by 0.5 percent. However, in most prior periods, January production usually exceeds December production by no more than 1 to 2 percent. See Appendix C, Schedule 4 for 1982 through 1987 winter season production data.

The December surplus figures cannot be scaled-up to achieve a measure of the industry-wide December capacity surplus. The survey respondents might or might not be representative of the nation's natural gas producers.

REGIONAL GAS PRODUCTIVE CAPACITY & SALES TRENDS

Overview of Regional Trends

A. Connected And Unconnected Gas Well Capacity

Total connected and unconnected capacity (herein called: "total gas well capacity") declined in almost all of the survey regions shown in Table 1. The percentage change in total gas well capacity, however, varies greatly from region to region. The largest declines in total gas well capacity have occurred in the Pacific (-9.8%), the Onshore Gulf (-9.6%), the Permian & San Juan Basin (-7.3%) regions. Conversely, the smallest declines in total gas well capacity occurred in Appalachia (-0.9%), the Rocky Mountains (-4.0%), the Anadarko (-4.1%), and the Offshore Gulf (-4.2%). Of all the regions, only the North Central posted an increase in total gas well capacity amounting to 9.8 percent. The drilling success in the Michigan Basin is probably responsible for this increase in North Central gas well capacity.

B. December 1987 and 1988 Gas Sales & Capacity Factors

Capacity factors change over time with the changes in connected well capacity and gas sales. Even though total December gas sales declined by 148 MMcf/day between 1987 and 1988, regional gas sales in Table 2 indicate that the regional sources of gas supply have shifted as well. The Offshore Gulf, Onshore Gulf, Permian & San Juan Basins, and the Pacific regions posted an aggregate gas sales loss of 411 MMcf/day between December 1987 and December 1988. Even though the four other regions did not recoup the full 411 MMcf/day in lost gas sales, they did increase their gas sales by a total of 263 MMcf/day.

In a few regions, this shift in December gas sales is responsible for the large year-to-year change in capacity factors. In particular, the changes in Rocky Mountain and Pacific capacity factors are due more to changes in gas sales than to changes in connected well capacity. Even though the Pacific's connected well capacity declined by 7.4 percent, December gas sales fell by 13.7 percent, thus resulting in a 4.9 percentage point drop in the Pacific's capacity utilization. Conversely, the Rocky Mountain region posted a 3.7 percent decline in well capacity while December gas sales increased by 16.3 percent, thereby causing the Rocky Mountain capacity factor to increase by 13.1 percentage points, going from a 63 percent capacity factor to a 76 percent capacity factor.

Of the eight survey regions, the highest December 1988 capacity factors are those posted for the Onshore Gulf (91.8%) and Appalachia (96.5%). Based on these capacity factors alone, it is clear that these two regions are the most supply constrained. For the Onshore Gulf region this notion is further reinforced by the fact that total gas well capacity fell by 9.6 percent, indicating an inability (either for economic or physical reasons) to maintain prior levels of gas capacity. Moreover, both of these regions posted the largest declines in unconnected well capacity: a 45.8 percent decline in the Onshore Gulf and a 83.3 percent decline in Appalachia. (The large percent decline in Appalachian capacity is of less real significance, given the small amounts of capacity that are involved.) The large decline in Onshore Gulf unconnected capacity is consistent with the notion that gas producers might be converting unconnected capacity into connected capacity in order to maintain as high a level of deliverability as is possible during a period of increasingly tighter supplies.

C. December 1987 and 1988 Gas Capacity Surpluses

As with the other measures associated with gas well productivity and sales, the individual regions show a great deal of variability in the year-to-year change in regional gas surpluses.

As is shown in Table 3, of the eight survey regions, only three posted an increase in the December capacity surplus: Appalachia (+33.3%), Pacific (+8.8%), and North Central (+5.3%). Even though these percentage increases in the regional capacity surplus appear to be significant, they are not because they collectively account for only 3.5 percent of the total connected capacity. Thus, these three regions collectively increased their gas capacity surplus by only 20 MMcf/day.

In contrast, the five other survey regions collectively posted a 1,312 MMcf/day decline in the capacity surplus. The largest declines in the capacity surplus occurred in the Offshore Gulf (-445 MMcf/day), the Onshore Gulf (-294 MMcf/day), and the Rocky Mountains (-229 MMcf/day). The most rapid diminishment of the capacity surplus occurred in the Onshore Gulf, where it declined by 39 percent. This rapid rate of decline again reinforces the notion, that of the major gas supply regions, the Onshore Gulf is clearly the one which is the most supply constrained.

The year-to-year change in a region's December gas surplus can be divided by the December 1988 surplus level as a measure for how quickly a region's sales and productive capacity are coming into balance. Larger rates of decline are indicative of regions with a more rapidly diminishing surplus. The surplus's rate of decline is provided for the following five survey regions which posted a decline in their surplus levels:

Region	December 1988 Surplus (MMcf/Day)	Changes In Surplus (MMcf/Day)	Rate of Decline In Surplus (% Per Yr)
Offshore Gulf	2,288	- 445	-19.4%
Onshore Gulf	459	- 294	-64.1%
Permian & San Juan	529	- 173	-32.7%
Anadarko	923	- 171	-18.5%
Rocky Mountain	378	- 229	-60.6%
All Eight Regions	**4,846**	**- 1,292**	**-26.7%**

Based on the above measure, again the Onshore Gulf region clearly has the tightest gas capacity situation followed by the Rocky Mountain region. However, the capacity and sales situation for these two regions are completely different. The tight capacity situation in the Onshore Gulf region has been partly alleviated by a reduction in gas sales. The tightening situation in the Rocky Mountains is due to the dramatic increase in gas sales.

Summary Of Regional Trends For The Five Major Survey Regions

A. Offshore Gulf

The Offshore Gulf region appears to be the least constrained by wellhead gas capacity of the five major survey regions (i.e., Offshore Gulf, Onshore Gulf, Permian & San Juan, Anadarko, and Rocky Mountain). In December 1988, the Offshore Gulf region posted an 80.7 percent capacity factor, which increased by only 2.6 percentage points from the prior December.

Because the Offshore Gulf region represents 43 percent of the survey's lower-48 connected well capacity, this region also posted the largest reduction in connected well capacity, which declined by 646 MMcf/day for a 5.2 percent reduction in this region's connected capacity.

The decrease in connected well capacity is partly offset by the 77 MMcf/day increase in unconnected well capacity. As a result, the total connected and unconnected capacity fell by only 4.2 percent, which is below the total lower-48 reduction of 5.7 percent.

B. Onshore Gulf Region

The Onshore Gulf is clearly the most supply constrained of the five major survey regions. This conclusion is reinforced from many perspectives, such as:

1) Of the five major regions, the Onshore Gulf posted the largest decline in connected and unconnected well capacity, dropping by 612 MMcf/day for a 9.6 percent reduction between 1/1/88 and 1/1/89.

2) Of the five major regions, the Onshore Gulf had the highest December capacity factors, amounting to 91.8 percent in December of 1988. This region also posted one of the larger increases in regional capacity factors, by increasing 4.3 percentage points.

3) The Onshore Gulf posted a 64 percent rate of decline in the December gas surplus.

4) The high capacity factor and the rapid rate of decline in the capacity surplus both occurred even though year-to-year December gas sales dropped by 2.6 percent.

C. Anadarko Basin

The Anadarko Basin shows considerable spare gas capacity with a December 1988 capacity factor of 77.6 percent, with the surplus diminishing at a rate of 18.5 percent per year.

Of the five major survey regions, the Anadarko posted the smallest percentage decline in connected well capacity (-2.3%). However, the 32.4 percent decline in unconnected well capacity resulted in a total capacity decline of 4.1 percent.

D. Permian & San Juan Basins

Relative to the other five major survey regions, the Permian & San Juan region appears to the second most supply constrained, after the Onshore Gulf region. This conclusion is based on the following survey results:

1) The Permian & San Juan region posts the second highest December 1988 capacity factor of 83.6 percent. Moreover, this capacity factor showed one of the highest year-to-year increases, amounting to a 4.2 percentage point increase.

2) The Permian & San Juan region's total well capacity declined by 7.3 percent between 1/1/88 and 1/1/89. This decline is the second largest of the five major regions.

3) The Permian & San Juan December surplus declined by about 33 percent. This is the second largest rate of decline if the Rocky Mountain region is excluded from consideration because of its large year-to-year sales increase.

E. Rocky Mountain Region

The Rocky Mountain region is most notable for its dramatic increase in December capacity factors by going from 63.1 percent in December 1987 to 76.1 percent in December 1988. This increase in capacity factors is mostly due to the 169 MMcf/day increase in December gas sales. Even with this dramatic increase in capacity factors, the Rocky Mountain region posted a 76.1 percent December 1988 capacity factor which is the lowest of all eight survey regions.

TABLE 1
1989 NGSA NATURAL GAS PRODUCER DELIVERABILITY SURVEY
CONNECTED & UNCONNECTED GAS WELL CAPACITY
(On A Dry Gas Basis)

	REGION	1/1/88	1/1/89	CHANGE IN MAGNITUDE	% CHANGE
CONNECTED GAS WELL CAPACITY (MMcf/Day)	OFF GULF	12,483	11,837	(646)	-5.2%
	ON GULF	6,000	5,568	(432)	-7.2%
	PER/SJ	3,403	3,218	(185)	-5.4%
	ANADARKO	4,227	4,128	(99)	-2.3%
	APPALACHIA	111	115	4	3.6%
	N. CENTRAL	236	259	23	9.7%
	ROCKY MTN.	1,643	1,583	(60)	-3.7%
	PACIFIC	609	564	(45)	-7.4%
	TOTAL	28,712	27,272	(1,440)	-5.0%
UNCONNECTED GAS WELL CAPACITY (MMcf/Day)	OFF GULF	929	1,006	77	8.3%
	ON GULF	393	213	(180)	-45.8%
	PER/SJ	307	220	(87)	-28.3%
	ANADARKO	262	177	(85)	-32.4%
	APPALACHIA	6	1	(5)	-83.3%
	N. CENTRAL	29	32	3	10.3%
	ROCKY MTN.	92	82	(10)	-10.9%
	PACIFIC	78	56	(22)	-28.2%
	TOTAL	2,096	1,787	(309)	-14.7%
TOTAL CONNECTED AND UNCONNECTED GAS WELL CAPACITY (MMcf/Day)	OFF GULF	13,412	12,843	(569)	-4.2%
	ON GULF	6,393	5,781	(612)	-9.6%
	PER/SJ	3,710	3,438	(272)	-7.3%
	ANADARKO	4,489	4,305	(184)	-4.1%
	APPALACHIA	117	116	(1)	-0.9%
	N. CENTRAL	265	291	26	9.8%
	ROCKY MTN.	1,735	1,665	(70)	-4.0%
	PACIFIC	687	620	(67)	-9.8%
	TOTAL	30,808	29,059	(1,749)	-5.7%

TABLE 2
1989 NGSA NATURAL GAS PRODUCER DELIVERABILITY SURVEY
CONNECTED GAS WELL DECEMBER CAPACITY FACTOR
(On A Dry Gas Basis)

	REGION	1/1/88	1/1/89	CHANGE IN MAGNITUDE	% CHANGE
CONNECTED GAS WELL CAPACITY (MMcf/Day)	OFF GULF	12,483	11,837	(646)	-5.2%
	ON GULF	6,000	5,568	(432)	-7.2%
	PER/SJ	3,403	3,218	(185)	-5.4%
	ANADARKO	4,227	4,128	(99)	-2.3%
	APPALACHIA	111	115	4	3.6%
	N. CENTRAL	236	259	23	9.7%
	ROCKY MTN.	1,643	1,583	(60)	-3.7%
	PACIFIC	609	564	(45)	-7.4%
	TOTAL	28,712	27,272	(1,440)	-5.0%
PRIOR YEAR DECEMBER GAS SALES (MMcf/Day)	OFF GULF	9,750	9,549	(201)	-2.1%
	ON GULF	5,247	5,109	(138)	-2.6%
	PER/SJ	2,701	2,689	(12)	-0.4%
	ANADARKO	3,133	3,205	72	2.3%
	APPALACHIA	108	111	3	2.8%
	N. CENTRAL	160	179	19	11.9%
	ROCKY MTN.	1,036	1,205	169	16.3%
	PACIFIC	439	379	(60)	-13.7%
	TOTAL	22,574	22,426	(148)	-0.7%
CONNECTED WELL DECEMBER CAPACITY FACTOR (%)	OFF GULF	78.1%	80.7%	2.6%	
	ON GULF	87.5%	91.8%	4.3%	
	PER/SJ	79.4%	83.6%	4.2%	
	ANADARKO	74.1%	77.6%	3.5%	
	APPALACHIA	97.3%	96.5%	-0.8%	
	N. CENTRAL	67.8%	69.1%	1.3%	
	ROCKY MTN.	63.1%	76.1%	13.1%	
	PACIFIC	72.1%	67.2%	-4.9%	
	TOTAL	78.6%	82.2%	3.6%	

TABLE 3
1989 NGSA NATURAL GAS PRODUCER DELIVERABILITY SURVEY
CONNECTED GAS WELL DECEMBER CAPACITY SURPLUS
(On A Dry Gas Basis)

	REGION	1/1/88	1/1/89	CHANGE IN MAGNITUDE	% CHANGE
CONNECTED GAS WELL CAPACITY (MMcf/Day)	OFF GULF	12,483	11,837	(646)	-5.2%
	ON GULF	6,000	5,568	(432)	-7.2%
	PER/SJ	3,403	3,218	(185)	-5.4%
	ANADARKO	4,227	4,128	(99)	-2.3%
	APPALACHIA	111	115	4	3.6%
	N. CENTRAL	236	259	23	9.7%
	ROCKY MTN.	1,643	1,583	(60)	-3.7%
	PACIFIC	609	564	(45)	-7.4%
	TOTAL	28,712	27,272	(1,440)	-5.0%
PRIOR YEAR DECEMBER GAS SALES (MMcf/Day)	OFF GULF	9,750	9,549	(201)	-2.1%
	ON GULF	5,247	5,109	(138)	-2.6%
	PER/SJ	2,701	2,689	(12)	-0.4%
	ANADARKO	3,133	3,205	72	2.3%
	APPALACHIA	108	111	3	2.8%
	N. CENTRAL	160	179	19	11.9%
	ROCKY MTN.	1,036	1,205	169	16.3%
	PACIFIC	439	379	(60)	-13.7%
	TOTAL	22,574	22,426	(148)	-0.7%
CONNECTED WELL DECEMBER CAPACITY SURPLUS (MMcf/Day)	OFF GULF	2,733	2,288	(445)	-16.3%
	ON GULF	753	459	(294)	-39.0%
	PER/SJ	702	529	(173)	-24.6%
	ANADARKO	1,094	923	(171)	-15.6%
	APPALACHIA	3	4	1	33.3%
	N. CENTRAL	76	80	4	5.3%
	ROCKY MTN.	607	378	(229)	-37.7%
	PACIFIC	170	185	15	8.8%
	TOTAL	6,138	4,846	(1,292)	-21.0%

APPENDIX A - SCHEDULE 1

PRODUCER PARTICIPANTS IN THE NGSA SALES & PRODUCTIVE CAPACITY SURVEY

1. Amoco Production Company
2. Anadarko Petroleum Corporation
3. ARCO Oil and Gas Company
4. Cabot Corp.
5. Chevron Oil & Gas
6. Columbus Energy Corporation
7. Conoco
8. Exxon Company, U.S.A.
9. Hamilton Brothers Oil Company
10. Hondo Oil & Gas
11. Kerr-McGee Corporation
12. Louisiana Land & Exploration
13. Marathon Oil Company
14. Mobil Natural Gas Co.
15. W. S. Osborn
16. OXY USA Inc.
17. Pennzoil Exploration & Production Co.
18. Phillips 66 Natural Gas Company
19. Shell Oil Company
20. Oryx (Sun Exploration)
21. Tenneco Oil
22. Texaco
23. Union Pacific Resources
24. Union Texas Petroleum
25. UNOCAL

APPENDIX A - SCHEDULE 2

DEFINITION OF NGSA SURVEY REGIONS

The survey asks for gas productive capacity and sales for eight lower-48 regions and for the total lower-48 as a whole. The regional breakdown was developed around the major gas production basins and the markets they serve. Forty two states are explicitly included in one of the eight regions. Only the six New England states are excluded. Any productive capacity in New England should be included in the Appalachia region.

1. Offshore Gulf Coast: Includes all the offshore Gulf production and capacity, both in state and federal jurisdictions, for the states of Alabama. Florida, Louisiana, Mississippi, and Texas.

2. Onshore Gulf Coast: Includes all onshore production and capacity for Alabama, Florida, Georgia, Louisiana, Mississippi, and Texas Railroad Districts: 1, 2, 3, 4, 5, & 6.

3. Permian and San Juan Basins: Includes all of New Mexico, and Texas Railroad Districts: 7B, 7C, 8, and 8A.

4. Anadarko Basin: Includes Arkansas, Kansas, Oklahoma, and Texas Railroad Districts: 9 and 10.

5. Appalachia: All onshore and offshore gas production and deliverability for the states of: Delaware, Kentucky, Maryland, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, and West Virginia.

6. North Central: Includes Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, and Wisconsin.

7. Rocky Mountain: Includes Arizona, Colorado, Idaho, Montana, Nebraska, North Dakota, South Dakota, Utah, and Wyoming.

8. Pacific: Includes both onshore and offshore production and deliverability associated with California, Nevada, Oregon, and Washington.

9. Total U.S. Lower-48: Should include both onshore and offshore production and deliverability for all the regions listed above plus New England.

APPENDIX A - SCHEDULE 3

TOTAL SURVEY RESPONSE
NATURAL GAS SUPPLY ASSOCIATION (NGSA)
1989 NATURAL GAS SALES & PRODUCTIVE
CAPACITY SURVEY

BASIS(WET/DRY): CONVERTED TO UNIFORM DRY BASIS	FORM A: QUESTION A:		QUESTION B:		QUESTION C:	
	CONNECTED WELL CAPACITY (MMcf/Day)		ANNUAL PERCENTAGE CONNECTED CAPACITY ADJUSTMENT (Percent)		UNCONNECTED WELL CAPACITY (MMcf/Day)	
LOWER-48 REGIONS	YEAR AGO On 1/1/1988	CURRENT On 1/1/1989	YEAR AGO On 1/1/1988	CURRENT On 1/1/1989	YEAR AGO On 1/1/1988	CURRENT On 1/1/1989
OFFSHORE GULF COAST	12,483.46	11,837.44	84.04 %	85.68 %	929.47	1,005.77
ONSHORE GULF COAST	5,999.68	5,567.96	96.60	92.52	392.72	213.08
PERMIAN & SAN JUAN BASIN	3,403.43	3,218.23	89.38	89.67	307.47	219.78
ANADARKO BASIN	4,226.93	4,127.92	90.77	93.35	261.69	177.23
APPALACHIA	110.73	115.07	93.81	92.51	5.95	1.00
NORTH CENTRAL	235.91	259.49	94.80	94.97	28.52	31.92
ROCKY MOUNTAIN	1,642.99	1,583.01	88.48	91.14	92.28	81.67
PACIFIC	609.02	563.67	85.65 %	85.69 %	77.75	55.92
TOTAL U.S. LOWER-48	28,712.14	27,272.79	88.70 % (A)	89.14 % (A)	2,095.86	1,786.37

(A) Total Represents Weighted Average of Question A and B.

APPENDIX A - SCHEDULE 3 (Continued)

TOTAL SURVEY RESPONSE
NATURAL GAS SUPPLY ASSOCIATION (NGSA)
1989 NATURAL GAS SALES & PRODUCTIVE
CAPACITY SURVEY

FORM B:

QUESTION D:		QUESTION E:	
TOTAL NATURAL GAS SALES (MMcf/Day)		TOTAL DRY CASINGHEAD GAS PRODUCTION (MMcf/Day)	
YEAR AGO DECEMBER 1987	CURRENT DECEMBER 1988	YEAR AGO DECEMBER 1987	CURRENT DECEMBER 1988
9,749.63	9,548.52	463.83	443.01
5,247.19	5,108.68	490.47	436.64
2,700.58	2,689.07	631.58	537.74
3,133.35	3,205.48	265.48	260.92
108.05	110.74	9.20	8.00
159.60	178.64	23.04	21.66
1,036.38	1,205.03	123.41	130.07
439.31	379.20	160.37	151.33
22,574.09	22,425.35	2,167.37	1,989.38

APPENDIX B - SCHEDULE 1
NGSA GAS PRODUCER DELIVERABILITY SURVEY
RATIO OF REGIONAL DRY GAS RESERVES TO WET GAS RESERVES

REGION	TOTAL GAS (BCF, WET)	TOTAL GAS (BCF, DRY)	GAS DRY /GAS WET RATIO
ALABAMA ONSHORE	889	842	0.947
ALASKA	33,715	33,225	0.985
ARKANSAS	2,018	1,997	0.990
CALIFORNIA	3,893	3,740	0.961
COASTAL ONSHORE	255	238	0.933
LOS ANGELES ONSHORE	155	148	0.955
SAN JOAQUIN ONSHORE	3,229	3,102	0.961
STATE OFFSHORE	254	252	0.992
COLORADO	3,131	2,942	0.940
FLORIDA	62	49	0.790
KANSAS	11,089	10,494	0.946
KENTUCKY	940	909	0.967
LOUISIANA	12,852	12,430	0.967
NORTH	2,350	2,306	0.981
SOUTH ONSHORE	9,024	8,693	0.963
STATE OFFSHORE	1,478	1,431	0.968
MICHIGAN	1,571	1,451	0.924
MISSISSIPPI	1,223	1,220	0.998
MONTANA	801	780	0.974
NEW MEXICO	12,621	11,620	0.921
EAST	3,133	2,881	0.920
WEST	9,488	8,739	0.921
NEW YORK	410	410	1.000
NORTH DAKOTA	578	508	0.879
OHIO	1,071	1,069	0.998
OKLAHOMA	17,703	16,711	0.944
PENNSYLVANIA	1,650	1,647	0.998
TEXAS	42,192	38,711	0.917
RRC DIST #1	844	812	0.962
RRC DIST #2 ONSHORE	2,373	2,273	0.958
RRC DIST #3 ONSHORE	3,859	3,632	0.941
RRC DIST #4 ONSHORE	7,768	7,490	0.964
RRC DIST #5	2,224	2,119	0.953
RRC DIST #6	4,962	4,682	0.944
RRC DIST #7B	828	697	0.842
RRC DIST #7C	3,032	2,708	0.893
RRC DIST #8	7,871	6,999	0.889
RRC DIST #8A	1,301	876	0.673
RRC DIST #9	984	834	0.848
RRC DIST #10	5,512	4,962	0.900
STATE OFFSHORE	634	627	0.989
UTAH	2,341	1,947	0.832
VIRGINIA	248	248	1.000
WEST VIRGINIA	2,360	2,242	0.950
WYOMING	10,572	10,023	0.948
FEDERAL OFFSHORE	32,432	31,931	0.985
PACIFIC COAST	1,466	1,452	0.990
GULF OF MEXICO (LA.)	23,705	23,260	0.981
GULF OF MEXICO (TEXAS)	7,261	7,219	0.994
MISCELLANEOUS	66	65	0.985
U.S. TOTAL	196,428	187,211	0.953
NGSA LOWER-48 SURVEY REGIONS			
OFFSHORE GULF	33,078	32,537	0.984
ONSHORE GULF	35,578	34,118	0.959
PERMIAN/SAN JUAN	25,653	22,900	0.893
ANADARKO	37,306	34,998	0.938
APPALACHIA	6,679	6,525	0.977
NORTH CENTRAL	1,571	1,451	0.924
ROCKY MOUNTAIN	17,423	16,200	0.930
PACIFIC	5,359	5,192	0.969
TOTAL LOWER-48	162,647	153,921	0.946
ALASKA	33,715	33,225	0.985
MISCELLANEOUS	66	65	0.985
U.S. TOTAL	196,428	187,211	0.953

(SOURCE: U.S. Crude Oil, Natural Gas, And Natural Gas Liquids Reserves: 1987 Annual Report, Energy Information Administration, DOE/EIA-0216(87) Oct. 27, 1988, pages 26 & 29.)

APPENDIX C
SCHEDULE 1

ESTIMATED LOWER-48 NATURAL GAS PRODUCTION IN DECEMBER OF 1987 AND 1988
(On A Dry Gas Basis)

	DEC. 87	DEC. 88
TOTAL U.S. DRY GAS PRODUCTION 1/		
IN Bcf/Month	1,533	1,510
IN MMcf/Day	49,452	48,710
ALASKAN RESERVES (Bcf) 2/		
ON A WET BASIS	33,715	
ON A DRY BASIS	33,225	
DRY/WET RATIO	0.985	
ALASKAN MARKETED PRODUCTION 1/		
IN MMCF	33,728	35,762
IN MMCF/DAY	1,088	1,154
ALASKAN GAS PRODUCTION ON A DRY BASIS (MMcf/Day)	1,072	1,137
ESTIMATED LOWER-48 DRY GAS PRODUCTION (MMcf/Day)	48,379	47,573
NGSA SURVEY'S DRY GAS PRODUCTION (MMcf/Day)	22,574	22,425
NGSA SURVEY COVERAGE OF INDUSTRY	46.7%	47.1%

1/ Source: "Natural Gas Monthly", DOE/EIA-0130(89/03) Table 7, pages 17-19.

2/ SOURCE: "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1987 Annual Report" DOE/EIA-0216(87), pages 26 & 29.

APPENDIX C - SCHEDULE 2
1989 NGSA NATURAL GAS PRODUCER DELIVERABILITY SURVEY
COMPARISON OF SURVEY RESPONDENT REGIONAL PRODUCTION TO EIA'S TOTAL ANNUAL REGIONAL GAS PRODUCTION

	REGION	DEC. '87	PERCENT OF TOTAL	DEC. '88	PERCENT OF TOTAL
NGSA SURVEY PRIOR YEAR DECEMBER GAS SALES (MMcf/Day)	OFF GULF	9,750	43.2%	9,549	42.6%
	ON GULF	5,247	23.2%	5,109	22.8%
	PER/SJ	2,701	12.0%	2,689	12.0%
	ANADARKO	3,133	13.9%	3,205	14.3%
	APPALACHIA	108	0.5%	111	0.5%
	N. CENTRAL	160	0.7%	179	0.8%
	ROCKY MTN.	1,036	4.6%	1,205	5.4%
	PACIFIC	439	1.9%	379	1.7%
	TOTAL	22,574	100.0%	22,426	100.0%

		1987 ANNUAL TOTAL	
DOE/EIA DATA ON ANNUAL DRY GAS SALES BY REGION 1/ (Bcf/Year)	OFF GULF	4,726	30.0%
	ON GULF	4,482	28.4%
	PER/SJ	1,780	11.3%
	ANADARKO	2,962	18.8%
	APPALACHIA	513	3.3%
	N. CENTRAL	130	0.8%
	ROCKY MTN.	774	4.9%
	PACIFIC	391	2.5%
	TOTAL	15,758	100.0%

1/ Source: "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1987 Annual Report", DOE/EIA-0216(87), Oct. 27, 1988, Table 11, page 29. 7 Bcf excluded from the totals and the regional breakdown because this gas was lumped into an "Other" category which was not differentiated by state or region.

APPENDIX C - SCHEDULE 3
COMPARISON OF DECEMBER NATURAL GAS PRODUCTION TO THE PRODUCTION LEVELS OF OTHER WINTER HEATING SEASON MONTHS

YEAR	MONTH	NATURAL GAS PRODUCTION (Bcf, Dry)	NATURAL GAS CONSUMPTION (Bcf, Dry)	RATIO OF MONTHLY PRODUCTION TO DECEMBER LEVELS
1982	NOV.	1,415	1,559	0.98
	DEC.	1,448	1,739	1.00
1983	JAN.	1,464	1,975	1.01
	FEB.	1,289	1,642	0.89
	MAR.	1,335	1,591	0.92
1983	NOV.	1,389	1,503	0.91
	DEC.	1,530	2,191	1.00
1984	JAN.	1,644	2,260	1.07
	FEB.	1,428	1,739	0.93
	MAR.	1,469	1,851	0.96
1984	NOV.	1,419	1,644	0.92
	DEC.	1,539	1,844	1.00
1985	JAN.	1,559	2,101	1.01
	FEB.	1,416	2,148	0.92
	MAR.	1,413	1,719	0.92
1985	NOV.	1,332	1,313	0.87
	DEC.	1,537	1,903	1.00
1986	JAN.	1,536	2,106	1.00
	FEB.	1,333	1,849	0.87
	MAR.	1,415	1,703	0.92
1986	NOV.	1,366	1,276	0.93
	DEC.	1,473	1,710	1.00
1987	JAN.	1,500	1,998	1.02
	FEB.	1,347	1,818	0.91
	MAR.	1,426	1,674	0.97

Source: "Natural Gas Monthly", Energy Information Administration, various editions, Tables 1 & 3.

APPENDIX D - SCHEDULE 1

1988 NATURAL GAS RESERVE CHANGES FOR THE NGSA DELIVERABILITY SURVEY
(SOURCE: PARENT COMPANY ANNUAL REPORTS AND SEC 10-K)

PRODUCER	1987 END OF YEAR RESERVES	RESERVE REVISIONS	IMPROVED RECOVERY	PURCHASES OF MINERALS IN PLACE	EXTENSIONS & DISCOVERIES	PRODUCTION	SALES OF MINERALS IN PLACE	OTHER ADJUSTMENTS	1988 END OF YEAR RESERVES	PRODUCTION REPLACEMENT FROM EXTENSIONS & DISCOVERIES	PRODUCTION REPLACEMENT FROM REVISIONS, EXTENSIONS & DISCOVERIES
	(Bcf)	(Bcf)	(Bcf)	(Bcf)	(Bcf)	(Bcf)	(Bcf)	(Bcf)	(Bcf)	(%)	(%)
1 AMOCO	10,690.0	397.0	6.0	1,405.0	544.0	(605.0)	(66.0)		12,371.0	90.9	156.5
2 ANADARKO PETROLEUM	1,717.1	47.8		9.6	75.9	(128.5)		(18.0)	1,703.9	59.1	96.2
3 ARCO	5,854.0	415.0	41.0	45.0	620.0	(508.0)	(19.0)	(75.0)	6,373.0	130.1	211.8
4 CABOT CORP.	494.6	15.0		1.2	62.1	(38.0)	(1.3)		533.6	163.5	203.1
5 CHEVRON	7,078.0	475.0	1.0	1,324.0	184.0	(740.0)	(48.0)		8,274.0	25.0	89.2
6 COLUMBUS ENERGY CORP.	6.6	(0.8)			0.0	(0.4)			5.5	3.4	(224.6)
7 CONOCO (DU PONT)	1,959.0	198.0		137.0	100.0	(238.0)	(2.0)		2,154.0	42.0	125.2
8 EXXON	9,761.0	64.0	10.0	125.0	132.0	(751.0)			9,341.0	18.9	27.4
9 HAMILTON BROTHERS OIL CO.	31.9	8.1			4.9	(6.0)			38.8	80.6	215.6
10 HONDO OIL & GAS CO.	4.4	2.5		122.3	1.5	(13.7)	(8.3)		108.7	11.0	29.3
11 KERR-McGEE CORP.	563.8	76.0		39.2	51.6	(84.8)			645.8	60.8	150.5
12 MARATHON/TEXAS OIL & GAS (USX)	3,277.6	(68.2)	2.2	14.0	153.4	(313.5)	(17.8)		3,047.7	49.6	27.9
13 MOBIL	7,741.0	356.0			84.0	(658.0)	(8.0)		7,515.0	12.8	66.9
14 OXY U.S.A.	2,734.0	40.0		4.0	79.0	(282.0)	(7.0)		2,568.0	28.0	42.2
15 PENNZOIL	821.0	126.0		14.0	56.0	(124.0)	(2.0)		891.0	45.2	146.8
16 PHILLIPS	3,369.0	145.0		7.0	166.0	(312.0)	(10.0)		3,365.0	53.2	99.7
17 SHELL	6,541.0	(125.0)	11.0	72.0	426.0	(581.0)	(96.0)		6,248.0	75.2	53.7
18 ORYX ENERGY	2,232.0	(11.0)	1.0	45.0	219.0	(247.0)	(54.0)	57.0	2,242.0	89.1	84.6
19 TEXACO	4,783.0	621.0	25.0		91.0	(780.0)	(85.0)		4,655.0	14.9	94.5
20 UNION PACIFIC (CHAMPLIN)	1,474.1	57.0			140.4	(145.0)	(8.8)		1,517.7	96.8	136.1
21 UNION TEXAS PETROLEUM	331.7	(4.5)		14.1	103.8	(54.1)			391.0	192.0	183.6
22 UNOCAL	4,399.0	(67.0)		50.0	214.0	(276.0)			4,320.0	77.5	53.3
TOTAL	75,863.7	2,766.9	97.2	3,428.4	3,508.6	(6,885.9)	(433.1)	(36.0)	78,309.8	52.4	92.5

APPENDIX D - SCHEDULE 2

1988 NGSA DELIVERABILITY SURVEY
ESTIMATED DELIVERABILITY DEPLETION RATES

PRODUCER	YEAR-END 1987 PROVED DEVELOPED GAS RESERVES	YEAR-END 1988 PROVED DEVELOPED GAS RESERVES	AVERAGE 1988 PROVED DEVELOPED GAS RESERVES	1988 PRODUCTION	AVERAGE 1988 PROVED DEVELOPED RESERVE-PRODUCTION RATIO	AVERAGE 1988 PROVED DEVELOPED RESERVES DEPLETION RATE
	(Bcf)	(Bcf)	(Bcf)	(Bcf)	(Years)	(% per Year)
1 AMOCO	9,931.0	11,313.0	10,622.0	605.0	17.56	5.7%
2 ANADARKO PETROLEUM	1,649.8	1,667.5	1,658.6	128.5	12.90	7.7%
3 ARCO	4,806.0	5,420.0	5,113.0	508.0	10.06	9.9%
4 CABOT CORP.	470.6	512.8	491.7	38.0	12.96	7.7%
5 CHEVRON	6,627.0	7,617.0	7,122.0	740.0	9.62	10.4%
6 COLUMBUS ENERGY CORP.	5.5	4.3	4.9	0.4	13.77	7.3%
7 CONOCO (DU PONT)	1,843.0	2,004.0	1,923.5	238.0	8.08	12.4%
8 EXXON	8,579.0	8,090.0	8,334.5	751.0	11.10	9.0%
9 HAMILTON BROTHERS OIL CO.	31.7	38.0	34.9	6.0	5.78	17.3%
10 HONDO OIL & GAS CO.	4.4	105.7	55.0	13.7	4.02	24.9%
11 KERR-McGEE CORP.	422.0	423.7	422.9	84.8	4.99	20.1%
12 MARATHON/TEXAS OIL & GAS (USX)	2,376.6	2,264.3	2,320.4	313.5	7.40	13.5%
13 MOBIL	6,493.0	6,243.0	6,368.0	658.0	9.68	10.3%
14 OXY U.S.A.	2,146.0	2,042.0	2,094.0	282.0	7.43	13.5%
15 PENNZOIL	773.0	763.0	768.0	124.6	6.19	16.1%
16 PHILLIPS	3,091.0	3,086.0	3,088.5	312.0	9.90	10.1%
17 SHELL	4,977.0	4,686.0	4,831.5	581.0	8.32	12.0%
18 ORYX ENERGY	1,707.0	1,710.0	1,708.5	247.0	6.92	14.5%
19 TEXACO	4,547.0	4,381.0	4,464.0	780.0	5.72	17.5%
20 UNION PACIFIC (CHAMPLIN)	1,257.5	1,325.9	1,291.7	145.0	8.91	11.2%
21 UNION TEXAS PETROLEUM	239.4	266.4	252.9	54.1	4.68	21.4%
22 UNOCAL	2,937.0	2,819.0	2,878.0	276.0	10.43	9.6%
TOTAL	64,914.4	66,782.5	65,848.5	6,885.9	9.56	10.5%

September 11, 1989

Mr. Robert E. Kallman
Executive Director
The President's Outer Continental Shelf
Leasing and Development Task Force
18th & C Streets, N.W.
Washington, D.C. 20240

Dear Mr. Kallman:

The undersigned natural gas associations - American Gas Association (AGA), The Interstate Natural Gas Association of America (INGAA), and the Natural Gas Supply Association (NGSA) - represent companies engaged in the production, transmission, and distribution of natural gas. Together, the undersigned associations represent a substantial majority of the natural gas produced, transmitted, and distributed in the United States.

This letter is in response to your August 11, 1989, Federal Register Notice requesting additional comments regarding environmental concerns associated with oil and gas production in three Outer Continental Shelf (OCS) areas. As a preliminary matter, we oppose any federal or state effort to ban natural gas production in the areas under consideration. Our reasons and justifications for our position are discussed more fully below. However, based on the record of safety of OCS operations in the past and the contribution that natural gas use can make to meeting national environmental goals it is imperative that new supplies of natural gas be permitted to be developed.

It is well documented that natural gas can make significant contributions to improving the nation's air quality. Indeed, some of the same environmental organizations that have attended your public meetings, workshops, and have submitted comments, are lauding the use of natural gas, citing its relatively low levels of emissions, particularly sulfur dioxide. Natural gas is by far the cleanest burning fossil fuel since it produces less carbon dioxide per unit of energy output. We welcome the environmental community's support for the increased use of natural gas to solve some of our nation's pressing environmental problems and look forward to working with those organizations in the future.

Industry and government geologists believe that natural gas resources are both plentiful and abundant in the OCS. We need access to those areas to assure an adequate supply of natural gas in the future. Without access to those areas, we could face future supply and deliverability problems at a time when the use of natural gas in the United States is on the increase. The Department of Energy projects U.S. natural gas consumption to rise by 5.4 percent by 1995 and another 7 percent by the year 2000. If the nation is to reap the environmental and economic benefits of increased natural gas use, access must be granted without further political or regulatory delay. Simply wishing that natural gas resources might be in areas that are environmentally less sensitive is not a practicable or realistic proposition -- especially given the excellent offshore safety record which the industry enjoys in developing natural gas resources without significant harm to the environment. Nevertheless, many commentators and participants in your public workshops have ignored the industry's OCS record and have instead relied on supposition and innuendo to support their allegations.

Numerous commentators suggested that they are opposed to OCS oil and gas development due to oil spill risks that could occur. Many state that their concerns are justified given the recent tanker accident in Alaska. These concerns are simply misplaced. Most offshore production reaches the mainland by pipeline, which enjoys an exemplary safety record. There has not been a major spill from oil and gas operations in the OCS in two decades. Moreover, if OCS areas are precluded from further oil and gas development, we will have to acquire more of our supplies from abroad. Some of those supplies will reach the United States by tankers. Such increased tanker traffic heightens the risk of another oil spill. Furthermore, relying on foreign oil and natural gas production also raises national security problems. The United States is currently importing more than 50 percent of its oil consumption. Thus, access to the OCS will not only reduce our growing dependence on foreign oil and gas but would lessen the risks of future oil spills. Such considerations should play an important part when deciding whether the OCS areas could be used for oil and gas production.

Another recurring comment concerns the effects of oil and gas development on tourism. We feel that these arguments are also invalid. Tourism is more affected by the costs of transportation than by the presence of offshore drilling rigs. If OCS areas are precluded from further oil and gas production, the laws of supply and demand would dictate that fuel costs may increase. Accordingly, we feel that an adequate supply of oil and gas will do more to benefit the tourist industry by maintaining lower fuel costs to consumers.

Finally, a review of the comments and transcripts of your public hearings would lead one to believe that there are currently not any environmental safeguards in place concerning production and transmission from the OCS. Nothing is farther from the truth. Offshore producers face stringent safety rules and regulations; lengthy federal, state, and local permitting process; and extensive environmental studies. We are committed to complying with those requirements and will maintain our commitment to other reasonable, well-balanced regulations that may be required in the future.

In conclusion, the debate over the development of the OCS reflects a lack of understanding about energy sources and is a critical limitation to U.S. efforts to maintain adequate supplies. We feel a balance can be found between current environmental concerns and maintaining our nation's need for energy. Furthermore, limiting the ability to search for and produce natural gas in the OCS will hinder our ability to make significant environmental contributions. Consequently, we urge you to support OCS development for environmental reasons, energy security reasons, and to assure that consumers will continue to enjoy adequate energy supplies at reasonable costs.

G H Lawrence
George H. Lawrence, President
American Gas Association (AGA)

Jerald V Halvorsen
Jerald V. Halvorsen, President
Interstate Natural Gas Association
of America (INGAA)

Nicholas J Bush
Nicholas J. Bush, President
Natural Gas Supply Association (NGSA)

cc: The Honorable Manuel Lujan, Jr.
Secretary of the Interior

Senator **Bingaman**. Our final witness today is Mr. Bud Lawrence, who is President of the American Gas Association. We are very pleased to have you here.

STATEMENT OF GEORGE H. LAWRENCE, PRESIDENT, AMERICAN GAS ASSOCIATION

Mr. **Lawrence**. Senator, thank you.

And as I listen to Mr. Bush and Mr. Conklin, I am so gratified by the common view we have on the prospects for our industry.

In fact, as I listened to Secretary Moore, your colleagues, and most of the witnesses here today, the outlook is very positive. And the principal reason for this optimism on natural gas is this removal of federal intrusions on both the supply and demand side of our business.

And this subcommittee and this full committee led the way on that with the Natural Gas Policy Act of 1978, the repeal of the Fuel Use Act in 1987, and the final decontrol legislation that the President signed in July of this year.

And because of your efforts, natural gas is going to play an increasingly important role to our nation's environmental and energy security priorities.

But it seems, as we have heard here today and as one of the principal substances of your hearing, it seems there will always be lingering uncertainty in some quarters on gas supply. The theory is that, as the bubble ends and supply and demand come in balance, energy prices will stay too low to stimulate exploration and drilling. And, frankly, we do not see it that way.

No group is more concerned about this supply situation and security of supply than the distribution, transmission and member companies of AGA, because they have the ultimate supply obligation to serve American gas consumers.

Now our companies have carefully analyzed supply issues for all time frames. The immediate, i.e., this winter; and this short-term period through the early to mid-1990s, the so-called transition zone, or the soft or hard landing; and then the long term, through the year 2010. In fact, we have completed four major studies that we have attached to the prepared testimony.

And first, we find that yes, the bubble, as we predicted it for some time, we think it will still end this winter and early next year. But a 50 percent increase in gas storage capability from the early 1970s means that we are going to have adequate deliverability this winter.

In fact, this study, entitled "Natural Gas for the Winter Heating Season," estimates that we will have, in the one-month capability, greater than the coldest month in January of 1979 for any one month throughput over the last 15 years.

Now, they talk about spot cold prices, and if we have a cold winter we cannot make it. Do you remember the January of 1988? There was a two-week period there when there was a nationwide average of 40 percent colder than normal, and there was not a ripple in the system. It handled it.

Okay.

Second is the mid-term. There are four sources of gas that we think can be brought on within a very short period of time to make this landing soft and not hard. Canadian imports, in-fill wells, currently non-producing reserves, and LNG terminals that are currently empty, and people are willing to sell gas in here now at a competitive price. We think it can increase supplies seven-tenths, to 1.4 TCF within a 12-month period.

Now, third, is the long term. And this is a study we do biannually, and it comes out this year, to the year 2010.

Now, the nation has an increasingly gas-prone resource base that can continue to supply between 20 and 25 percent of our nation's total energy consumption.

Now, importantly, these supplies will come on at price scenarios high, low and medium. But, in all cases, available supply in 2010 should be at least 18.4 TCF, and that is more than the consumption last year.

And the upper end of the price range, supplies could be as high as over 24 trillion cubic feet.

And a very important point of this, this includes a steadily increasing contribution from the lower 48 states in all price scenarios, straight through to the year 2010.

Now, a fourth study that we have made that is very important, oil and gas producers have been through a serious restructuring and downturn, but there are clear indications that they are very bullish on U.S. natural gas, and that they are restructuring their drilling efforts to tap that resource base.

Indeed, we see this increased demand for natural gas, and Mr. Conklin referred to that, and the fact that much of this is a new high value gas, that does not compete with the lowest energy kid on the block, is going to be a real stimulus to exploration and drilling.

We have seen gas well completions increase 6.5 percent in the first half of this year, while oil well completions were down over 40 percent. Rig counts have increased from a low early this year of around 750 to 967 last month.

Our estimate is, by the end of this year, they will be in the range of 1,100; they need to go higher. But it is the increasingly focused effort on the gas-prone resource base that has to be the principal reason for the EIA reserve additions in 1988 being 130 percent of production at a time of very low rig activity.

And Mr. Sawhill says a lot of that is revisions and extensions and so forth. Extensions and revisions have been a part of reserve estimates for 40 years. They always will be and should be.

Well, anyway, to keep these efforts going and to further stimulate drilling, we do need tax credits. We know you have been supportive of that. And especially the extension of the tax credits from hard to produce gas resources, such as coal seams, devonian shale, tide formation, geopressure binds, et cetera.

Now, in just one of these categories, and a lot of it was in your home state, coal seams, it added a proved reserve addition in 1988 of just about a trillion cubic feet.

We are strongly supportive of increased OCS leasing, which Mr. Bush referred to.

And I would be happy to respond to any efforts that we can be helpful on that point.

Finally, the outlook for natural gas is strong. The resource base is huge and is now poised to respond to market signals as never before. The transportation system, as Mr. Tussing indicated, is sufficient, it is extensive and it is flexible.

Storage capability is at its peak again; over 50 percent larger than in the early 1970s. And our companies can handle increases in gas demand. And this increase in gas demand is going to be coming in some very exciting new markets: high efficiency electric generation, natural gas cooling, natural gas vehicles—we used to talk about those things a lot; not much was being done about them, but now a lot is being done about them.

And the main reason for this growing recognition of the role of gas energy among customers and public officials is this increased confidence in long-term gas supply; and that confidence is justified.

Thank you.

[The prepared statement of Mr. Lawrence follows and additional material appears in Appendix II:]

TESTIMONY
OF
GEORGE H. LAWRENCE
PRESIDENT OF THE
AMERICAN GAS ASSOCIATION
BEFORE THE
SUBCOMMITTEE ON MINERAL
RESOURCES AND DEVELOPMENT
OF THE
ENERGY AND NATURAL RESOURCES COMMITTEE
UNITED STATES SENATE
ON
NATURAL GAS SUPPLIES
AND RESOURCES

September 26, 1989

Executive Summary

The natural gas industry has successfully emerged from a period of restrictions on gas demand;[1/] from wellhead price controls;[2/] from high cost take-or-pay contracts;[3/] and the implementation of a new open and nondiscriminatory transportation system.[4/] Despite these successes, there is lingering uncertainty about gas supplies. Uncertainty is caused by a long period of surplus production capability (the gas "bubble"), which has lowered wellhead prices and consequently reduced exploration and drilling.

No group is more concerned about security of supply than the 250 natural gas distribution and transmission companies that comprise the American Gas Association (A.G.A.). Together, these companies sell or deliver gas to over 84% of the gas consumers in the United States. There are 172 million American gas consumers. Consequently, A.G.A. recently completed a series of analyses, investigating supply issues. We conclude:

> **First, the natural gas "bubble", or production surplus, is expected to be gone by 1990.** See: Section I., below.
>
> Second, the disappearance of the "bubble" does not mean that there will not be enough firm gas in the future. **Nationally, there should be adequate firm gas deliverabiity this winter.**[5/]

Although production capability this winter may be 10 percent lower than actual production at the beginning of the decade, new gas storage capability more than makes up for the decrease. Since 1980, gas storage capability has increased as much as 50 percent. See: Section II., below.

Third, there has been speculation about a possible supply shortage in the 1990s, based on fears that exploration and production will not rebound quickly enough after the drilling slump of the late 1980s.

In contrast, A.G.A. believes that a **balance of supply and demand is far more likely than an unstable gas supply system** that operates out of control by cycling from shortage-to-surplus-to-shortage. Our analysis is based on the fact that there is extensive dual fuel capability in the industrial market; increased gas storage capability; and four important gas supply categories that could be brought into production quickly -- generally less than 12 months, with full regulatory support. See: Section III., below.

Fourth, the North American natural gas resource base can continue to supply at least 20 - 25 percent of our nation's total energy through the year 2010, under a variety of price scenarios. Importantly, under low, middle, and high oil/gas price scenarios, 18.4 to 24.2 trillion cubic feet (Tcf) of gas supplies should be available in 2010. See: Section IV., below.

Fifth, although drilling is depressed, the news from the gas patch is not doom and gloom. The Energy Information Agency's (EIA's) latest estimates indicate an increase of 6.5% in the number of gas well completions through June 1989, compared to 1988 levels. We should stimulate this effort with tax credits, especially for production from tight formations, coalbed methane, and Devonian shale. See: Section V., below.

I.

Supply-Demand Balance

The End of the Natural Gas Bubble*

The excess natural gas production capability or "bubble" that has dominated natural gas markets since 1980 is expected to be gone by 1990. Although estimates of production capability are highly susceptible to error, there is probably about 850 billion cubic feet (Bcf) of unused production capability this year. This excess capability will decrease to close to zero during the 1989-90 winter. When that happens, we expect more price volatility in the spot market, but we also expect that the current, less-regulated gas market will be able to operate successfully with a nearly balanced supply and demand picture.

Two factors caused the bubble to shrink since its 1983 peak of 4.6 Tcf. They are: (1) declining domestic production capability as drilling slumped because of low energy prices and shut-in gas production; and (2) higher gas demand, primarily because of lower natural gas prices.

As the gas surplus ends, it is important to estimate how much nationwide production capability has declined during the 1980s to determine whether we can expect shortages, as some fear, or whether we can expect supply and demand to balance. To investigate this issue, A.G.A. looked at actual daily peak month production, in the 5 major producing states, between 1980 and 1989. See: Table 1. Our general conclusion is that while production is typically lower in the last half of the decade, demonstrated national production capability has held up, at 88 - 90 percent of the 1980 level.

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*Section I. is excerpted from Natural Gas Production Capability - 1989 - 1990, (Issue Brief 1989-12), The American Gas Association, Arlington, Va. (July 25, 1989).

Thus, our analysis indicates that nationally, under the worst case, a decline of 10 to 12 percent from 1980 is possible, (but at best there has been little loss in production capability over the period). Our estimate of production capability, coupled with the increases in natural gas storage capability (discussed in Section II., below), indicate that the industry is well-prepared to meet peak, firm demand.

At the same time, there is little slack in the system during winter, peak periods. Given the lack of excess supplies, some interruptible or "best efforts" customers are likely to be interrupted, as permitted by their contacts and lower rate structures. Interuptibility should not be misinterpreted as "gas shortages" but rather, the way the industry will operate during peaks. Therefore, the end of the gas bubble could result in less reliable gas service to customers who have chosen the lowest cost/less reliable supplies. In addition, spot market price variations can be expected.

II.

Adequate Gas Deliverability This Winter*

The A.G.A. Gas Supply Committee surveyed pipelines, LDCs, and for the first time, producers, on their ability to satisfy their customers' requirements this winter. Their results show that, on a national average basis, there should be adequate gas deliverability this winter. Assuming that production capability for January 1990 is 10 percent lower than actual production at the start of the decade, gas storage send-out capability will be up to 50 percent greater than actual storage withdrawals 10 years ago. Thus, no imbalance between supply and demand for firm service is expected.

In reaching this conclusion, the Supply Committee considered the following factors:

- The maximum monthly consumption of gas ever recorded in the U.S. was 2,426 Bcf in January 1979. Peak supply capability for the winter of 1989/90 is projected to be 2,444 Bcf. This peak supply is based on 3 primary supply sources:
  1). maximum sustainable monthly January production of 1,600 Bcf (conservatively estimated to be 10 percent below actual 1980 production);
  2). peak storage capability of 700 Bcf (up from 576 Bcf of actual withdrawals in 1988 and 697 Bcf of previously demonstrated one month capability); and

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*Section II. is excerpted from Natural Gas For the Winter Season, The Gas Supply Committee, the American Gas Association, Alrington, Va. (September 1989).

3). Canadian gas supplies of 150 Bcf (up from the 138 Bcf previously demonstrated one month high in January 1988).

The Supply Committee noted at the outset that gas supplies this winter will reach the market under different contract conditions than in the recent past. Storage and spot gas will make-up a larger portion of LDCs' requirements. At the same time, gas sold by pipelines will probably be 41 percent of total peak month requirements in January 1990, compared to 76 percent of requirements in January 1980.

The change in the way that LDCs contract for gas supplies is part of the massive restructuring that the natural gas industry has undergone during the 1980s. In the past, pipelines sold nearly all of the LDCs' summer and winter gas supplies. No more. Now, spot gas has substantially replaced pipeline sales or "system" gas in both peak and off-peak periods. Therefore, pipelines significantly reduced their reserves under contract, resulting in about a 40 percent drop in the deliverability of pipeline owned gas. Since this gas has been released by interstate pipelines, it has become the backbone of the spot market. Although it is the same gas as before, of course, it is now sold under different contractual and regulatory conditions (see below).

> The Committee found:
>
> The ability of spot gas to satisfy seasonal gas requirements is basically untested during a period of relative gas supply/demand balance.
>
> The primary mechanism for spot gas volumes to react to increased demand, such as cold weather, is by price variations. This was clearly demonstrated during the last two winter heating seasons. Such temporary price run-ups and run-downs are likely again this winter. Several factors indicate that spot market prices are likely to become more volatile. The demand for spot gas is growing because: (1) total gas demand is increasing; (2) pipeline system sales are declining; (3) national production capability is declining; and (4) LDC and pipeline purchases of spot market gas will reinforce demand during cold weather.[6/] .

As to spot gas, the Supply Committee expects spot supplies to be allocated by price-bidding, rather than federal curtailment priorities. Because of transportation bottlenecks and sharp increases in gas demand due to cold weather, spot prices can be volatile. When asked to evaluate spot market price changes, LDCs estimated that, if January 1990 were the coldest winter in 50 years, they would pay 4.8 percent more for gas in January 1990 than they did in January 1988.

III.

Four Gas Supply Sources Can Be Tapped Quickly to Even-Out the Supply Picture*

Recently, there has been extensive speculation about the possibility of a gas supply shortage in the 1990s because of the drilling slump in the last half of the 1980s. Such shortages are projected because of fears that: (1) gas exploration and production will be unable to rebound after the long drilling slump; and (2) crude oil and natural gas prices will stay depressed even as gas supplies get tight, continuing to depress drilling activity.

Despite these theories, the existence of: extensive dual fuel capability; increased storage capability (discussed in II., above); and several gas supply sources that can be quickly brought to market, will prevent supply disruptions. Therefore, we do not believe that the current gas surplus will end in future gas shortages.

In the near-term, the balance between supply and demand depends on: (1) new gas supplies that can enter the market quickly; and (2) processes to allocate supplies to end users during high demand. In regard to (2), a robust spot market and interruptible contracts can allocate end use supplies. In regard to (1), short-term supplies can move into the market and bridge the gap between existing supplies and increasing demand.

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*Section III. is excerpted from Short-Term Gas Supplky Potential - 1989 Update, (Energy Analysis 1989-8), The American Gas Association, Arlington, Va. (August 25, 1989).

The magnitude of the short-term gas supply response depends on the amount of lead time that producers, pipelines, LDCs, and regulators need. In 12 months, from 0.7 to 1.4 Tcf more gas could be available, each year, from sources such as currently nonproducing reserves, Canadian imports, accelerated infill drilling and LNG imports. With a 36-month lead time, from 1.3 Tcf to 2.1 Tcf of gas could be available annually, from these same sources.

The existence of these "bridge" supplies should reduce speculation that a sudden surge in demand could cause supply shortages.

- As to nonproducing reserves, EIA annually reports the volume of proved reserves in nonproducing reservoirs as of December 31. At year end 1987, EIA estimated 29.2 Tcf of nonproducing reserves in the lower-48 states. Various impediments keep these volumes, which are not included in our "bubble" estimates, from coming into production immediately. For example, some of these reserves require small gathering system extensions or offshore platforms. Based on pre-bubble data from

1977 - 1981, on how long it took to develop nonproducing reserves in the past, A.G.A. estimates that 250 - 750 Bcf of nonproducing reserves could be developed within 12 months and 500 - 1,000 Bcf within 36 months. See: Table 2.

- Another supply source, Canadian gas, can provide secure, reliable, and plentiful gas supplies to the United States. U.S. companies currently have contracts with Canadian pipelines and producers to import up to 1.5 Tcf/yr., which is about the current pipeline capability. However, when seasonal, marketing and physical deliverability constraints are considered, this capability is closer to 1.4 Tcf/yr. Given that 1988 Canadian imports totaled about 1283 Bcf, 400 to 500 Bcf/yr. of additional gas could be made available to U.S. purchasers.

It is estimated that 1.8 Tcf/yr. of Canadian gas could be imported into the United States with additional pipeline construction. Most of these construction projects have already been proposed to the national regulatory bodies.

Construction of pending major pipeline projects could increase total deliverability to 1.9 Tcf/yr.

Thus, 120 Bcf of additional Canadian gas is available immediately, with 400 Bcf available by the early 1990s.

- As to accelerated infill drilling, in the early 1980s gas deliverability increased as a result of extensive infill drilling into known gas fields. Several of the largest gas fields in the country are still good prospects for infill drilling to increase production capability and proved reserves. For example, infill drilling proposals by producers in the Hugoton basin have cited reserve increases as high as 7.6 Tcf. Similar proposals for accelerated drilling in the San Juan basin could add 1.4 Tcf of reserves. Nationwide, accelerated infill drilling could increase production capability by 0.1-0.4 Tcf/yr. in three years and 0.05 to 0.1 Tcf/yr. within the next 12 months.

Given that infill drilling is generally "low cost" drilling, the major constraints on infill development are: (1) lack of gas demand; (2) low gas prices, and (3) state well-spacing regulations. Constraint (3) is being lifted in a number of states, while (1) and (2) will be gone in 1990 when the bubble disappears.

- Lastly, there are four LNG terminals that have been operational and could become operational again. Collectively, these terminals have the capacity to handle about 850 Bcf per year. Competitive pricing for LNG imports depends on the willingness of the producing country to accept a wellhead price that is still competitive at the burner tip after the transportation costs are factored-in. Each exporting nation decides what its wellhead price will be. That price varies greatly depending on current economic and political conditions in the exporting country. Nevertheless, in the event that additional gas supplies were needed in the U.S., 50 Bcf of LNG could be imported within 12 months; up to 200 Bcf/yr. by the early 1990s; and up to 500 Bcf by the mid-1990s.

In summary, there is a short-term (12 to 36 month) potential gas supply of between 0.7 Tcf/yr. and 2.1 Tcf/yr. that could come on line if needed. These additional supplies should prevent shortages. They are a bridge source of natural gas during the time it takes the exploration and production industry to explore for and develop new longer-term supply sources.

IV.

Under all Price Scenarios -- Low, Mid-, and High -- North American Gas Supplies Will Be Available and Can Continue to Supply 20 -25 Percent of the Nation's Total Energy In the Year 2010*

Conventional gas production in the lower-48 states is currently, and will continue to be, our nation's most important source of gas into the next century. The Potential Gas Committee of the Colorado School of Mines estimates recoverable conventional national gas, in the lower-48 states, to be 831 Tcf, including proved reserves.

Although supplemental supplies (from sources other than lower-48 state production) currently provide less than 10 percent of total U.S. supplies, that percentage is likely to increase over the next 25 years. By the year 2010, supplemental sources, chiefly pipeline deliveries from conventional Canadian production, are expected to contribute from 18 to 20 percent of total gas supplies.[7/]

The development of the large North American resource base depends, of course, on the price of natural gas and oil,[8/] as well as technological advances.[9/] Consequently, the A.G.A. Gas Supply Committee used three price scenarios -- low, mid-, and high -- when developing a supply forecast for the year 2010.

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*Section IV. is excerpted from The Gas Energy supply OUtlook 1989 - 2010, The Gas Supply Committee, the American Gas Association, Arlington, Va. (September, 1989).

These three cases represent a pricing spectrum broad enough to both reflect plausible future prices and the price-sensitive supply responses of the different sources of gas. None of these scenarios is intended to be a "best guess" or is considered by the Committee as a most likely estimate of the future.

- The low price scenario assumes relatively flat oil prices in 1988 real dollars to the year 1995 at which time the oil price would be $18 per barrel (bbl). Beyond 1995, it assumes a steady 4% annual rise in oil prices, reaching $33/bbl (1988$) in 2010. The gas price associated with the $33/bbl oil price in 2010 is $4.84 per million British Thermal Units (MMBtu), almost three times the average wellhead price in 1988. This scenario assumes that OPEC cannot control cartel members very effectively and that there are surplus oil supplies -- a continuation of the situation that has prevailed in OPEC over the past few years. Also, competition between natural gas and residual fuel oil continues to influence gas prices. These factors dampen incentives to develop new gas resources over the period and result in the lowest gas supply estimate -- 18.4 Tcf. See: Table 3.

- The middle price scenario assumes more rapid growth rates in oil and gas prices in real terms. Growth begins in 1989 and leads to oil and gas prices respectively, of $27/bbl and $3.63/MMBtu in 2000, and $40/bbl and $5.52/MMBtu in 2010. In this scenario, world oil prices rise as increased oil demand reduces the world surplus of oil. Oil supply and demand cause prices to increase at an average real rate of 4.7 percent per year. Increasing energy prices provide additional incentives for the development of new gas supply sources. Thus, this scenario results in a higher gas supply response than the low price scenario -- 23.2 Tcf. See: Table 4.

- The high price scenario results in the highest oil and gas price levels and thus increases the economic incentive to develop a full array of gas supply sources. Under this scenario, the OPEC cartel is able to achieve a rapid escalation in oil prices. Thus, oil and gas prices rise to levels not unlike those anticipated by many studies in the early 1980s. By the year 2000, oil prices will have reached $38/bbl, with gas prices at $4.59/MMBtu. By 2010, oil prices increase to $62/bbl and gas prices reach $7.48/MMBtu (in 1988 dollars). These prices result in the highest level of domestic gas supply and availability -- 24.2 Tcf, which is especially important for minimizing U.S. imports of expensive foreign oil. See: Table 5.

In summary, based on the three price scenarios, the Supply Committee concluded:

- Available gas supply for the year 2010 should be, in all cases, at least 18.4 Tcf, compared to 17.7 Tcf of actual consumption in 1988.
- Estimated gas supply in the year 2010 is between 18.4 and 24.2 Tcf depending upon the pricing scenario. The 24.2 Tcf level represents a 37 percent increase over the 1988 level of actual gas supply.
- Average available supply for the three scenarios for the year 2010 is 21.9 Tcf per year, constituting an increase of 24 percent over the 1988 level of actual gas supply.
- Foreign overseas sources of LNG generally account for less than 4 percent of the total supply in all

scenarios. All imports, including those from Canada and Mexico, range between 11 and 14 percent of the total supply in the various scenarios.

- Sources of gas supply in the future should be more diverse and will tend to change depending on economic and technological development.
- Each scenario leads to a different configuration of sources in the gas supply forecast. In all cases supply was adequate for gas to maintain at least a 20-to-25 percent share of the nation's total energy. At the upper end of the range, sufficient resources appear to be available to increase supplies, if dictated by energy prices, as high as 24.2 Tcf.

V.

There are Indications That Natural Gas Drilling Is Recovering. Congress Should Foster Gas Resources By Enacting Tax Credits

The U.S. hydrocarbon resource base is becoming more gas-prone and producers have begun to invest in natural gas exploration and drilling efforts. Thus, oil well completions in 1989 continue to be down significantly from 1988 totals -- 39.2% lower through June, 1989 than in the previous year. In contrast, EIA reports 3,790 gas well completions through June 1989. This is 6.5% ahead of last year's January - June total of 3,560 gas well completions.[10/]

There are also other slight indications that drilling is resuming. For the second straight month, the monthly rotary rig count averaged in excess of 800 rigs. In fact, the average rig count for August 1989 was 886 rigs (6.5 percent more than the July 1989 average). Since March 1989, the rotary rig count monthly average has gained 133 rigs or 17.7%. The 54 rig increase from July to August was the largest monthly increase this year.

These "indications" certainly do not mean that drilling is returning to prior levels, but they do point out that, even in these tough times, gas producers can and do look for and find gas.

We believe that a package of tax incentives is particularly crucial to this effort. An extension of the existing tax credits for gas from geopressured brine, Devonian Shale, coal seams and tight formations is especially important. A 5 year extension of the existing tax credits, and other technical amendments, would: (1) stimulate drilling efforts; (2) substantially help this gas get to market; and (3) enhance the U.S. resource base.

CONCLUSION

The outlook for natural gas energy is very favorable. Our transportation system is flexible and capable of delivering energy throughout the nation through over one million miles of underground pipeline. The industry has a large, seasonal gas storage capability with a demonstrated 3.2 Tcf working gas capability. Even under the most unusual weather conditions, most gas distribution and transmission companies should be able to handle transitory increases in gas demand. Natural gas is also environmentally benign, cost competitive, and efficient. With its vast resource base and its extensive delivery system, natural gas can make more and more important contributions toward achieving national economic, environmental and energy security priorities.

Footnotes

[1] P.L. 100-42 repealing the Powerplant and Industrial Fuel Use Act (May 21, 1987).

[2] P.L. 101-60 providing for the decontrol of wellhead natural gas prices July 27, 1989).

[3] Order 436, F.E.R.C. Stats & Regs, par. 30,655, 50 Fed. Reg. 42,408 (October 18, 1985).

[4] See: Those portions of Order 500 providing for the passthrough of take-or-pay liabilities, FERC Stats & Regs, par. 30,761, 52 Fed. Reg. 30,334 (August 14, 1987).

[5] Our data is based on survey responses from over 70 LDCs. Well over 90% of these companies anticipated little or no difficulty in terms of adequacy of gas supplies for the coming winter heating season. Several companies were very cautious on this issue. If the weather were extremely cold, these companies anticipated spot market price increases and the potential for curtialment of low-priority non-dual fuel customers.

[6] The Gas Supply Committee, Natural Gas for the Winter Heating Season, American Gas Association, Alrington, VA. (September, 1989).

[7] Supplemental gas supplies from sources as diverse as Mexico, Alaska, and existing LNG terminals are likely, but are expected to be less than 1 Tcf through 2010.

[8] Oil prices effect the availability of gas. Associated gas accounts for 30 percent of total U.S. proven reserves and over the 1985 to 1987 period associated gas reserve additions averaged 19 percent of total U.S. gas reserve additions. Oil prices also affect gas supplies because oil drilling may result in gas reserve additions through "accidental" discoveries when gas is found although the target was oil.

[9] Advances in exploration technology by research institutes, producers and service companies have led to new judgements about the economic viability of some resources. For example, gas reserves at water depths greater than 1,000 meters in the Gulf of Mexico are resources that only a few years ago were thought to be technologically inaccessible but are now considered feasible at certain prices.

[10] Similarly, the American Petroleum Institute estimates gas well completions through June 1989 are 5% ahead of comparable 1988 totals. API estimates oil well completions at 39.9% below cumulative June 1988 statistics.

Table 1

DEMONSTRATED NATURAL GAS PRODUCTION IN PEAK MONTHS

	Daily Production Demonstrated in Peak Month*										Ratios				
State	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989[1]	1985/1980	1986/1980	1987/1980	1988/1980	1989[1]/1980
Kansas	3,270	2,188	2,191	2,057	1,967	2,194	1,903	1,929	1,948	1,607	.671	.582	.590	.596	.491
Louisiana	20,446	19,686	18,709	15,928	18,535	16,537	15,814	15,112	15,088	15,117	.809	.773	.739	.738	.739
New Mexico	3,339	3,339	3,307	2,972	3,061	3,148	2,420	2,804	2,727	2,551	.943	.725	.840	.817	.764
Oklahoma	6,444	6,252	6,611	5,608	6,182	6,246	5,846	5,932	5,698	5,964	.969	.907	.921	.884	.926
Texas	20,143	19,511	19,013	17,483	18,482	18,284	18,036	18,382	18,309	17,573	.908	.895	.913	.909	.872
Wyoming	1,308	1,345	1,378	1,509	1,588	1,356	1,502	1,690	1,981	2,247	1.037	1.148	1.292	1.515	1.718
U.S.	59,061	55,974	55,749	51,763	55,881	53,054	52,077	51,862	51,909	52,201	.898	.882	.878	.879	.884

*In MMcf

1. January-February only.

Source: EIA, Natural Gas Monthly, April 1989.

NOTE: Throughout this study, gas volumes (i.e., Tcf, Bcf, etc.) are used in lieu of energy values in Btu (i.e., quadrillion Btu or trillion Btu). The conversion factor employed is taken from the EIA Monthly Energy Review of March 1989. This conversion factor is 1,031 Btu per cubic foot of natural gas.

Table 2
Lower-48 Proved Reserves of Natural Gas
In Nonproducing Reservoirs
(in Bcf)

Year	Reserves	Nonproducing Reserves[1]	Reserve Life Index[2]	Average Reserves In Nonproducing Reserves 1977-81	Production Potential[3]	Actual Production[4]	Possible Increase In Production[5]
1977	175,170	25,228	8.05	23,175	-	-	-
1978	175,988	23,947	8.18	23,175	-	-	-
1979	168,738	21,248	7.75	23,175	-	-	-
1980	165,639	22,745	7.73	23,175	-	-	-
1981	168,693	22,708	7.89	23,175	-	-	-
1982	166,522	22,383	8.36	23,175	18,099	17,245	854
1983	165,964	23,454	9.19	23,175	18,029	15,515	2,514
1984	162,987	24,842	8.19	23,175	17,653	16,869	784
1985	159,522	30,277	8.25	23,175	17,216	15,673	1,543
1986	158,922	30,135	8.43	23,175	17,140	15,286	1,854
1987	153,986	29,210	7.91	23,175	16,517	15,765	752

Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids, Energy Information Administration, Annual Reports.

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1. Reported wet (with liquids) by EIA. The values listed have been corrected to dry volumes.
2. These reserve life indices were calculated for the lower-48 states using only the proved reserves in producing reservoirs. Hence, these values are lower than the indices normally reported.
3. Production potential is the difference of lower-48 reserves (column 2) and the average reserves in nonproducing reservoirs (1977-1981) (tabulated in column 5) divided by the average reserve life index (column 4) from 1977 to 1981. This value is an estimate of the total deliverability of the gas reserves.
4. Lower-48 dry production.
5. Estimates of incremental production which could come from the larger-than-usual volume of nonproducing reservoirs.

Table 3

Gas Supply - Low Price Scenario

(in Tcf)

	1988 Actual Supply	Available Supply 1995	2000	2010
Oil Price Assumption ($1988/bbl)	$14.71	$18	$22	$33
Gas Price Assumption ($1988/MMBtu)	$1.66	$2.33	$3.03	$4.84
Lower-48*	16.4	15.0	15.0	15.0
Imports				
Canadian	1.3	1.7	1.8	1.8
Mexican	-	-	0.1	0.1
LNG	**	0.2	0.4	0.6
Alaskan Gas				
Pipeline	-	-	-	0.8
Other Supplemental Sources	0.1	0.1	0.1	0.1
Totals (rounded)	17.8	17.0	17.4	18.4

*Lower-48 Production includes gas from tight formations, coal seams, and coproduction.

**Less than 25 Bcf.

Table 4

Gas Supply - Middle Price Scenario

(in Tcf)

	1988 Actual Supply	Available Supply 1995	2000	2010
Oil Price Assumption ($1988/bbl)	$14.71	$20	$27	$40
Gas Price Assumption ($1988/MMBtu)	$1.66	$2.59	$3.63	$5.52
Lower-48*	16.4	16.9	18.0	18.5
Imports				
Canadian	1.3	1.8	2.0	2.5
Mexican	-	-	-	-
LNG	**	0.4	0.6	0.8
Alaskan Gas Pipeline	-	-	0.8	1.2
Other Supplemental Sources	0.1	0.1	0.1	0.2
Totals (rounded)	17.8	19.2	21.5	23.2

*Lower-48 Production includes gas from tight formations, coal seams, and coproduction.

**Less than 25 Bcf.

Table 5

Gas Supply - High Price Scenario

(in Tcf)

	1988 Actual Supply	Available Supply 1995	Available Supply 2000	Available Supply 2010
Oil Price Assumption ($1988/bbl)	$14.71	$30	$38	$62
Gas Price Assumption ($1988/MMBtu)	$1.66	$3.62	$4.59	$7.48
Lower-48*	16.4	17.5	18.8	19.5
Imports				
Canadian	1.3	1.8	2.0	2.5
Mexican	-	-	-	-
LNG	**	0.5	0.8	0.8
Alaskan Gas Pipeline	-	-	1.2	1.2
Other Supplemental Sources	0.1	0.1	0.2	0.2
Totals (rounded)	17.7	19.9	23.0	24.2

*Lower-48 Production includes gas from tight formations, coal seams, and coproduction.

**Less than 25 Bcf.

Senator **Bingaman**. Thank you very much.

I think all of this testimony has been very useful in giving us a broad perspective on where this situation is going in the next few years. There are a lot of questions that remain unanswered, but I think, given the time, I will leave it at that and just thank all the witnesses very much for being here and testifying.

As we go forward in the next few months, I am sure we will have additional issues that affect the natural gas industry that we will want to call on all of you for your advice on.

Thank you all very much.

We may have some follow-up questions in written form we will submit.

We will leave the record open for the next few weeks.

The committee stands adjourned.

[Whereupon, at 4:40 p.m., the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Additional Questions

Department of Energy
Washington, DC 20585

December 11, 1989

The Honorable Jeff Bingaman
Chairman
Subcommittee on Mineral Resources
Development and Production
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

On September 26, 1989, Deputy Secretary W. Henson Moore gave testimony on natural gas supply and deliverability before your subcommittee.

Following that hearing, you submitted written questions on behalf of yourself and Senator Howard M. Metzenbaum to supplement the record. Enclosed are the answers to those questions, which also have been sent to Senator Metzenbaum.

If you have any questions, please have your staff call Michael Gilmore on 586-4277. He will be happy to assist.

Sincerely,

Joseph C. Karpinski
Principal Deputy Assistant Secretary
Congressional and Intergovernmental Affairs

Enclosure

QUESTIONS FROM SENATOR BINGAMAN

Natural Gas Imports

Question 1: Currently, imported natural gas accounts for less than ten percent of the United States natural gas consumption. During the 1990s, what role will natural gas imports play in meeting domestic natural gas demand?

Answer: In 1988, imported natural gas supplies were approximately seven percent of the total U.S. consumption. In 1988, Canada supplied about 98.6 percent of total imports to the U.S.

Natural gas imports are expected to supply as much as 11 percent of total U.S. annual gas consumption by the year 2000.

QUESTIONS FROM SENATOR BINGAMAN

Competitiveness of Domestic Producers

Question 2: Has the Department of Energy conducted any analysis of the competitiveness of domestic natural gas producers with foreign producers in terms of regulatory policy, tax incentives, and other governmental policy that may have an impact on competitiveness?

Answer: Yes. In the context of the analysis of the U.S.-Canada Free Trade Agreement, the Department examined the competitive situation between the U.S. and Canada. Specifically, we examined many complaints by independent producers regarding the competitive situation between domestic natural gas and Canadian imports. In general, we found that the problems they raised were not the result of Canadian regulatory policies. In many instances, the problems they raised were due to the transition in the U.S. gas market from a heavily regulated market to one more responsive to market forces.

There are, however, two situations where Canadian gas is developed and traded under different regulations than those facing domestic gas.

First, some have argued that the special regulatory treatment, under the Alaska Natural Gas Transportation Act and the FERC's implementation of that Act, given to the Alaska Natural Gas Transportation System (ANGTS) Prebuild may encourage greater imports of gas into the United States than would be the case if the Prebuild received traditional regulatory treatment. The Prebuild is a two-leg pipeline originating in Alberta and running to the Midwest and to California, and is intended to be part of a yet to be built larger pipeline system (the ANGTS) to deliver Alaskan gas to the Lower 48. Because of the perception that the United States was experiencing a gas shortage in the late 1970's, the U.S. government made commitments to Canada that the Federal Energy Regulatory Commission (FERC) would give special rate treatment to the Prebuild in order to encourage private investors to build the pipeline from Canada into the United States. These guarantees were seen as necessary to assuage fears that the rest of the ANGTS system would not be completed.

Therefore, some argue that these commitments may have the effect, under certain conditions, of favoring consumption of Canadian gas, over domestic gas. Regulatory policy and the gas market have changed in both countries since these commitments were made. Many have argued that despite these changes, the commitments cannot be changed. The Bush Administration intends to honor the commitments made to Canada. We will, however, use the National Energy Strategy process to analyze the effect of these commitments on domestic and Canadian producers, the availability of gas supply and the eventual completion of the entire ANGTS.

Second, with regard to tax issues, a 1988 DOE working paper entitled, "U.S. and Canadian Tax and Fiscal Treatment of Oil and Gas Production," concluded that "the cumulative effect of the various Canadian incentive programs [existing at the time of the study] makes investment in Canadian oil and gas production more attractive than investment in otherwise comparable U.S. oil and gas production." Some of the Canadian tax laws have changed since that paper that lessen this effect. We intend to evaluate the current situation of incentives within the context of the National Energy Strategy process.

WORKING PAPER

U.S. AND CANADIAN TAX AND FISCAL TREATMENT OF OIL AND GAS PRODUCTION

U.S. Department of Energy
Office of Policy, Planning and Analysis
Division of Oil, Economic, and Energy Tax Policy

Revised
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U.S. AND CANADIAN TAX AND FISCAL TREATMENT OF OIL AND GAS PRODUCTION

Introduction

On January 2, 1988, President Reagan and Prime Minister Mulroney signed the U.S.-Canada Free Trade Agreement (FTA). Congress will be asked to approve the Agreement this year. If approved, the FTA will create the largest free trade area in the world, and could become a model for agreements with other U.S. trading partners.

During the hearings on the FTA, concern was expressed that Canada's tax and royalty systems give it's oil and gas producers a competitive advantage over U.S. producers. Since the hearings on the FTA, Canada has announced a new incentive program for oil and gas exploration. This working paper has been revised to reflect this and other changes.

This document reviews the Canadian and U.S. tax and royalty systems. It compares the statutory provisions affecting crude oil and natural gas production in each country, and attempts, where possible, to analyze the comparative economic impacts of each system.*

Findings

From the following analysis, several observations can be made:

- The cumulative effect of the various Canadian incentive programs makes investment in Canadian oil and gas production more attractive than investment in otherwise comparable U.S. oil and gas production.
- Small producers operating within the limits of Canadian incentives, experience lower overall tax and royalty obligations than comparable producers operating in the United States.
- Larger integrated producers also receive the benefits of the Canadian incentives. However, once these larger producers exceed the incentive limitations, the effect of the incentives on additional drilling decisions diminishes.

It should be noted that the Canadian and U.S. tax and fiscal systems differ in so many significant respects that exact comparison is difficult.

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* This document was requested by and supplied to the Senate Committee on Finance in connection with hearings on the Free Trade Agreement. Since the original drafts of the document were completed, additional verification and analysis have resulted in the revisions contained herein. A more comprehensive review of the comparative economic impacts of foreign and domestic tax and fiscal systems requires additional, ongoing analysis that is described in more detail in the attached appendix.

Overview

The U.S.- Canada Free Trade Agreement does not affect incentives for oil and gas activities in either country. The U.S.-Canada Free Trade Agreement (FTA) does not require changing the tax or fiscal laws of either the United States or Canada as part of the initial implementation of the Agreement. The FTA guarantees each country the right to keep existing oil and gas incentives as well as the right to enact additional incentives.

Under Article 906 of the FTA, both countries have agreed "to allow existing or future incentives for oil and gas exploration, development and related activities in order to maintain the reserve base for these energy resources." Additionally, in Article 1902 of the Agreement, "each Party reserves the right to apply its anti-dumping law and countervailing duty law" in the event of a violation of its law.

Tax and fiscal incentives increase the rate of return from investments in Canadian oil and gas production. The United States and Canada have extremely different tax and fiscal regimes, making direct comparisons difficult. Since 1985, the Canadian Federal Government and three of its Provincial governments (Alberta, British Columbia, and Saskatchewan) have instituted numerous fiscal changes, many of which were in response to the collapse of world oil prices. In general, these new fiscal policies reflect the Canadian governments' willingness to forego current revenues in an effort to aid their oil and gas industry. As a result, the rate of return available from investments in Canadian oil and gas production has increased.

The United States, on the other hand, has just emerged from a long and hard-fought process of tax reform. The major goals of U.S. tax reform were to achieve: (1) lower marginal tax rates, and (2) a *tax-neutral* investment climate within the United States. This was intended to create relatively equal tax treatment between *service-intensive* and *capital-intensive* industries. Given these overriding goals, implementing investment incentives for domestic crude oil and natural gas production was not considered appropriate.

Canada implemented tax and fiscal incentives to maintain its oil and gas reserve base and to prevent the demise of small producers. In response to the oil price collapse of 1986, Canada adopted the *Canadian Exploration and Development Incentive Program* (CEDIP). When Canada announced this new program, it expected that the program's annual cost would not exceed C$ 350 million, and would generate an estimated C$ 1 billion per year in new exploration and development activity. However, current estimates by the Canadian Government indicate that the amount of the CEDIP refunds will decline to approximately C$ 175 million, for the fiscal year beginning April 1, 1989. Other significant changes in Canadian tax and fiscal policies include the following:

- Canada repealed the *Incremental Oil Revenue Tax* and the *Petroleum and Gas Revenue Tax* – its versions of the *Windfall Profit Tax;*

- Canada has proposed a new exploratory incentive program that will be available to *pass through* business entities.

- Canada has proposed the phased-in reduction of its corporate income tax rates;

- The Province of Alberta granted 1, 3 and 5-year royalty holidays for certain oil wells, a 1-year holiday for certain gas wells and a 75 percent royalty tax credit (previously 95 percent) against Provincial income taxes for up to C$ 3 million per taxpayer;

- The Province of British Columbia expanded its crude oil royalty holiday to include certain natural gas wells; and

- The Province of Saskatchewan implemented a system of price-sensitive oil and gas royalties, including relief for waterfloods and enhanced oil recovery projects.

Not all of the changes in the Canadian tax and fiscal systems were favorable to oil and gas producers. At about the same time the Canadian government phased out its investment tax credits (ITC), it also reimposed a 3-percent Federal surtax to its existing Federal corporate income tax structure. This increased the top Canadian corporate tax rate to 36.05 percent. During this time, the Alberta Provincial Government also implemented a 4-percent corporate income tax increase, and the Saskatchewan Provincial Government implemented a new natural gas freehold tax. A freehold tax is paid by the producer to the Provincial Government, in lieu of Provincial royalties, when a productive well is located on private property.

The United States has retained certain tax provisions that are intended to encourage oil and gas development. During the tax reform process, a deduction for percentage depletion for independent producers was retained. Independent producers in the United States may elect to deduct the "intangible" expenses of drilling both exploratory and developmental wells in the year they are drilled. The United States tax code provides quicker depreciation schedules for drilling equipment as well as lease and well equipment, and it allows deductions for State income and severance taxes when computing income subject to Federal income tax liability.

The United States also has retained or enacted certain other tax provisions that can discourage oil and gas exploration and development. There are certain existing provisions of U.S. tax law that tend to discourage oil and gas production. First, the *Windfall Profit Tax* imposes a tax on certain domestic crude oil of up to 70 percent of sales price in excess of $19.41 per barrel. Second, a *transfer rule* prohibits the use of *percentage depletion* on a proven oil or gas property that was transferred after 1974. Third, the 50 percent of net income and 65 percent of taxable income limitations reduce the amount of percentage depletion available. These measures can discourage efficient operation of marginally profitable oil and gas wells and encourage the premature abandonment of these wells.

Additionally, under the U.S. tax code, certain expenditures for intangible drilling costs and deductions taken for percentage depletion are considered *preference items* and are therefore added back to *taxable income* when computing alternative minimum tax liability. These and other tax provisions, together with royalties and State severance taxes, which are computed on gross revenue rather than net income of U.S. oil and gas investments, can discourage exploration and development activities within the United States.

COMPARISON OF U.S. AND CANADIAN TAX SYSTEMS

The Canadian Tax System

The Canadian Exploration and Development Incentive Program and the new Canadian exploratory incentive program reduces the cost of drilling certain crude oil and natural gas wells. On June 25, 1987, Canada enacted the Canadian Exploration and Development Incentive Program Act (CEDIP). This program provides cash refunds from the Canadian Federal Government equal to one-third of certain eligible expenses incurred after March 31, 1987; and one-sixth of eligible expenditures incurred between October 1, 1988 and December 31, 1989.

Expenses eligible for the incentive program include intangible drilling costs of both exploratory and developmental oil and gas wells. Additional expenses that are eligible include conversions and recompletions of existing wells, site preparation, dry hole costs, and geological and geophysical expenses. Currently, each applicant may qualify for up to C$ 3.33 million per year in refunds. In 1989, each applicant may qualify only for C$ 1.67 million. The Canadian Government estimates that total CEDIP refunds of C$ 350 million will be awarded through March 1988; C$ 300 million through March 1989; and C$ 175 million through March 1990. Since the CEDIP refunds are only a small fraction of total exploration and development expenditures, it is difficult to identify the volumes of additional Canadian crude oil and natural gas that have been discovered as a direct result of this program.

Canada also has just announced a new exploratory incentive program (CEIP). As of October 1, 1988, this program is intended to allow oil and gas companies that use *flow-through share* financing to qualify for refunds of up to C$3 million per applicant per year. The new program is similar to CEDIP, however, developmental wells do not qualify and an applicant will not be able to use the same expenditures for reimbursement under both programs at the same time. The new exploratory program provides cash refunds of up to 30 percent of exploratory drilling expenses with a limit of C$ 10 million in expenses per applicant per year. The Canadian government expects the program to cost approximately C$200 million per year for oil and gas exploration, and mining. The program will be reviewed after two years to determine its effectiveness.

The Canadian Federal tax system currently has higher marginal corporate income tax rates but allows quicker recovery of *geological and geophysical* costs. In late 1987, Canada introduced its version of tax reform that included reductions in corporate income tax rates. These rate reductions are proposed to begin in July 1988. Until then, the highest Canadian corporate income tax rate will remain at 35 percent with an additional surtax equal to 3 percent of the 35 percent rate. After the phase-in of the lower rates, the top Canadian corporate income tax rate will be 28 percent and the surcharge will remain in effect. However, as long as Provincial income taxes and royalty payments remain non-deductible for Canadian Federal tax purposes (see below), the total effective Canadian tax burden will be higher. Currently, individual Provincial income tax rates are approximately 46 percent of Canadian Federal taxes, and additional surcharges apply. In comparison, the State of Texas has no personal State income taxes.

In contrast, however, Canada has much more favorable treatment of geological and geophysical (G&G) expenses. These expenses are normally costs associated with conducting seismic profiles and mapping underground formations. Geological and geophysical expenses occur long before production and thus are considered front-end costs of a project. In frontier areas, these costs can be significant. In Canada, G&G costs are treated as exploration expenses and thus are eligible to be expensed in the same year they are incurred. In the United States, however, when recoverable, geological and geophysical costs are recovered over the productive life of the property, resulting in a much longer recovery period. The harder it is to find remaining U.S. crude oil and natural gas reserves, the more sophisticated and expensive are the G&G costs of any particular project.

The Canadian Federal tax system does not allow a deduction for Provincial income taxes and royalty payments, but does allow *flow through share* financing for oil , gas and mining operations and does grant a 25-percent resource allowance. As stated above, Canadian Provincial income taxes and royalty payments are not deductible in computing the amount of income subject to Canadian Federal income taxes. The Alberta Provincial corporate income tax rate is 15 percent of net income; in British Columbia it is 16 percent; and in Saskatchewan it is 17 percent. In an effort to reduce the after-tax burden of the non-deductability of Provincial taxes and royalties, the Canadian Federal Government passed a *resource allowance.* This allowance is computed at a rate of 25 percent of corporate *net income* and is a deduction from the Canadian Federal income tax burden. When computing *net income* for this purpose, a Canadian producer may not deduct the intangible costs of drilling a developmental well or the costs of acquiring a leasehold mineral interest.

Canada does, however, allow a *Principal Business Corporation* that invests in oil, gas or mining to *flow through* deductions to its shareholders. Upon sale of the shares only part of the proceeds is subject to Canadian Federal income taxation. *Principal Business Corporations* that use *flow through shares* to finance oil, gas, or mining operations are intended to qualify for the new Canadian Exploratory Incentive Program (CEIP).

Canada has repealed the *Incremental Oil Revenue Tax and the Petroleum and Gas Revenue Tax*, its versions of the *Windfall Profit Tax* In 1986, when crude oil prices collapsed, Canada repealed the Petroleum and Gas Revenue Tax. Canada previously repealed its short-lived Incremental Oil Revenue Tax. These taxes were first introduced in 1981 as part of Canada's *National Energy Program* . However, the Petroleum and Gas Revenue Tax was levied on income and royalties from both oil and gas production. Unlike the U.S. Windfall Profit Tax, revenues from the Canadian tax were used to finance Canada's *Petroleum Incentives Program.*

The United States Tax System

The United States grants an election to expense intangible drilling costs of both exploratory and developmental wells, but imposes alternative minimum tax liability on certain "excess" drilling expenses. The United States grants an election to deduct the intangible expenses of drilling both exploratory and developmental wells in the year that the drilling occurs. *Intangible drilling costs* (IDCs) include actual drilling costs, site preparation, access roads and other outlays that have no salvage value. Independent producers have an election to expense up to 100 percent of IDCs. Integrated producers may only elect to expense 70 percent of successful IDCs, with a five-year recovery of the balance. Oil and gas producers in Canada, however, recover the intangible costs of drilling developmental wells using a 30 percent declining balance method. Under this method of accounting, the costs of drilling developmental wells are recovered over a longer period..

During tax reform, the alternative minimum tax provisions were expanded to ensure that all U.S. taxpayers, including corporations, pay a fair share of the overall tax burden. As a result, many U.S. producers now must add back certain drilling expenses to taxable income when computing alternative minimum tax liability. This new provision, called the *excess IDC preference*, equals the amount of IDCs expensed, rather than amortized, that exceeds 65 percent of a producer's income from oil and gas operations. This provision reduces U.S. tax incentives for drilling by producers that are subject to alternative minimum tax liability. Additionally, this provision, coupled with other new and existing provisions and limitations, such as those limiting *passive losses, business interest deductions, net operating losses, and book income adjustments*, can reduce significantly the rate of return from investments in U.S. oil and gas production.

The United States grants independent producers current deductions for percentage depletion, but imposes strict limits on the use of these provisions. Independent producers in the United States are permitted to use percentage depletion. This can provide a deduction for as much as 15 percent of the value of the oil and gas produced from a property. However, when applicable, U.S. alternative minimum tax (AMT) is applied to the amount of the percentage depletion deduction taken by an independent producer in excess of the cost basis of the property.

The United States also has numerous limitations and prohibitions on the use of the percentage depletion deduction, such as the transfer rule on proven properties plus the 50 percent of net income and the 65 percent of taxable income limitations. Additionally, percentage depletion is available only on 1,000 barrels of crude oil (or its natural gas equivalent) per day and is available only on certain properties of independent producers. Canada repealed its version of percentage depletion. Canada has retained only a very small leasehold cost recovery provision and a provision for *earned depletion* for enhanced oil recovery projects. However, Canada's *earned depletion* provision is phasing out in 1989.

The U.S. allows accelerated depreciation for drilling and lease and well equipment but requires integrated producers to capitalize 30 percent of intangible drilling costs. The United States allows accelerated depreciation for drilling and for lease and well equipment through the use of 28 and 40 percent (double) declining balance methods of accounting and depreciation schedules of as few as 5 and 7 years. As much as 50 percent of the cost of drilling equipment is recovered within the first 3 years of making the expenditure. Canada uses a slightly less favorable 25 percent declining balance method. A producer using this method takes over eight years to recover 90 percent of its investment in lease and well equipment.

In the United States, integrated producers may elect to expense only 70 percent of their successful intangible drilling costs and must recover the remaining 30 percent over a 60-month period. Delayed recovery of IDCs significantly reduces the tax benefit of this provision.

The United States has retained its *Windfall Profit Tax* The Windfall Profit Tax was enacted in 1980 in response to the decontrol of crude oil prices. It imposed a tax on the difference between the *removal price* and the *base price* of taxable U.S. crude oil. The tax rates vary from a high of 70% on oil produced from properties that were in production before 1979 (Tier 1 properties) and a low of 20% for crude oil produced from *newly-discovered* properties. There also is an exemption for oil produced from certain stripper wells owned by independent producers.

Currently, this tax imposes significant paperwork costs on U.S. oil producers and produces little or no revenues for the Treasury. The Windfall Profit Tax discourages investment by producers to maintain or expand production on Tier 1 properties. Producers are discouraged from investing in such properties because the output would be subject to the Tier 1 tax rate of 70 percent when crude oil prices increase above the statutory base price. The base price for Tier 1 oil currently is $19.41 per barrel.

U.S. State and local governments also collect taxes and royalties from U.S. oil and gas production. State governments impose severance and income taxes and collect royalties on State lands. In the United States, however, a producer may deduct State income taxes and royalty payments when computing the amount of income subject to Federal income taxes. This reduces the effective tax burden of these payments. If a State wishes to provide incentives for oil and gas production, however, some portion of these incentives will be lost by the fact that more income will be subject to Federal income taxes. It should also be noted that State severance taxes, like royalties, are imposed on the gross revenues instead of the net income from investments in U.S. oil and gas production. Therefore, as oil and gas prices decrease, the percentage of net income from U.S. oil and gas investments taken in the form of severance taxes and royalties will increase.

U.S. State income and severance taxes vary widely. Severance taxes in Alaska are the highest at 15 percent, whereas Indiana's severance taxes are only 1 percent. Texas has a severance tax of 4.6 percent on crude oil and 7.5 percent on natural gas. State income taxes are just as variable.

COMPARISON OF U.S. AND CANADIAN ROYALTY SYSTEMS

The Canadian Royalty System

In the United States, most crude oil and natural gas production occurs on private lands. In Canada, however, crude oil and natural gas are produced primarily on lands owned by the Provincial governments. Consequently, Provincial governments have significantly more control over oil and gas economics than either the U.S. Federal or State governments. The Provinces establish royalties that fluctuate depending on both the amount of production and wellhead prices. Like the Canadian Provincial governments, however, many States in the U.S. have enacted tax incentives for marginal production and enhanced oil recovery projects.

The Province of Alberta has enacted royalty holidays for certain crude oil and natural gas wells and also has enacted a royalty tax credit. Alberta produces 81 percent of all Canadian crude oil production and 87 percent of all its natural gas production. It is estimated that 76 percent of Canada's total crude oil and natural gas reserves are located in Alberta. The royalty systems in Alberta, as in other Provinces, include different provisions for crude oil and natural gas.

- **Alberta's Crude Oil Royalty Provisions.** Alberta crude oil royalty rates vary according to the level of production per well and the level of oil prices. At today's wellhead prices (approximately $20 per barrel Canadian) the highest volume wells (100 barrels per day, or more) pay royalties of approximately 25 to 28 percent of gross revenue. Wells producing 20-100 barrels per day have royalty rates of 9 to 25 percent, while low volume wells (1-20 barrels per day) have 1 to 8 percent royalty rates. Old wells (pre-1974) producing less than 100 barrels per day have royalty rates 1-5 percent higher than new wells. Old wells producing over 100 barrels per day pay 5-10 percent higher royalties than new wells. Most old wells produce less than 100 barrels per day.

  A number of incentive programs, some temporary in nature, reduce or selectively eliminate the actual amount of royalties payable to the Provincial Government in Alberta. These include "royalty holidays" for exploratory wells, royalty relief for EOR projects and refundable royalty credits that lower the amount of Alberta Provincial income taxes payable. Royalty holidays are exemptions from payment of Provincial royalties for a set period.

  In Alberta, crude oil royalty holidays apply to exploratory wells drilled in unproven areas outside established pool boundaries or wells drilled deeper than any other well in an area. Qualified wells drilled between October 1986 and October 1987 are allowed a 5-year royalty holiday; qualified wells drilled between November 1987 and October 1988 are allowed a 3-year holiday; and other qualified wells drilled between November 1988 and the termination of the program in October 1989 will be allowed a 1-year royalty holiday. The Province of Alberta has not granted a royalty holiday for developmental crude oil wells.

  Enhanced oil recovery projects in Alberta are allowed to deduct approved costs before calculating royalties as long as the total amount of royalties collected is greater than or equal to the amount that would have been collected without the project. This condition is satisfied as long as the EOR project increases production enough so that the lower royalty rate still brings in the same or a greater amount of royalties.

  A royalty tax credit of 95 percent, adopted after the crude oil price collapse, was reduced to 75 percent effective January 1988. This tax credit, limited to C$ 3 million per taxpayer per year, is applied against Alberta Provincial income taxes and is refundable.

- **Alberta's Natural Gas Royalty Provisions.** Alberta's natural gas royalty rates also vary according to production volumes and wellhead prices. However, the natural gas royalty rate does not vary as much as the crude oil royalty rate. At today's wellhead prices -- approximately $2 per thousand cubic feet Canadian -- the highest volume wells (600 thousand cubic feet per day or more) are subject to royalties at a rate of 25 percent of gross revenue. However, for old gas, this rate increases to 40 percent as prices increase. Natural gas wells producing 150-600 thousand cubic feet per day are subject to royalty rates of 15 to 25 percent, while gas wells producing less than 150 thousand cubic feet per day are subject to 5 to 15 percent royalties. Old gas wells drilled before January 1974 are generally subject to higher royalty rates. Before the amount of the gas royalty is calculated, a *gas cost allowance* may be subtracted from the wellhead selling price of the natural gas. This represents the cost of producing and compressing the Province's share of production. In recent years, this allowance has been approximately C$ 0.54 per thousand cubic feet.

  The Province of Alberta granted royalty holidays for exploratory natural gas wells drilled in unproven areas and for wells drilled deeper than any other nearby well. Natural gas royalty holidays expire after one year and have a maximum value of $2 million (Canadian) per well. Exploratory gas wells drilled below 7500 feet qualify for an additional incentive that varies with depth and has a maximum value of C$ 3.6 million.

  Alberta also grants a refundable 75 percent royalty tax credit for natural gas production. This credit is limited to C$3 million per taxpayer per year. As with crude oil, this credit is applied against a producer's Alberta Provincial income taxes. This is a significant reduction of royalty burdens for natural gas production in Alberta. There is a proposal to reduce this credit to a 50 percent level with a C$2 million per taxpayer per year limitation.

The Province of British Columbia has enacted royalty holidays for certain exploratory and developmental oil and gas wells and has exempted certain EOR projects from royalty payments. British Columbia accounts for about 3 percent of total Canadian oil production and an estimated 10 percent of Canadian natural gas production. Like Alberta, British Columbia also has adopted separate incentives for oil and gas drilling and production.

- **British Columbia's Crude Oil Royalty Provisions.** The structure of British Columbia's crude oil royalty rates is very similar to that of Alberta. One difference, however, is that British Columbia's system does not respond to wellhead price changes. Old wells (pre-1975) producing 1-100 barrels per day have royalty rates 1-7 percent higher than for post-1975 wells. Royalties for old wells producing over 100 barrels per day are 7-10 percent higher than for post-1975 wells. In British Columbia there are very few old wells producing in excess of 100 barrels per day.

  British Columbia has enacted temporary royalty holidays for developmental and exploratory crude oil wells, and has granted royalty relief to several categories of EOR projects. There are no royalty tax credits in British Columbia.

  Certain crude oil wells drilled between July 1985 and June 1989 are allowed 3-year royalty holiday exemptions. The exemptions apply to exploratory oil wells drilled at least 7 km from any other producing well or drilled deeper than any other well in a 7 km radius. Unlike Alberta, British Columbia grants 2-year royalty holidays for developmental and infill wells drilled before June 1989.

  Enhanced oil recovery projects in British Columbia have different royalty provisions, depending on the nature of the project. Enhanced oil recovery projects that are considered experimental are permanently exempted from royalties. Other enhanced recovery projects receive lower royalty rates that are negotiated between the operator and the Province. Waterflood projects receive a two year royalty holiday, but do not receive negotiated rates after that period. Incremental production from EOR projects is treated as *new* oil, even if the original well was producing *old* oil before the project was initiated.

- **British Columbia's Natural Gas Royalty Provisions.** Currently, British Columbia's gas royalty rates are quite complex. The rates take into account the age of a well, its location, its depth, wellhead prices, and production volumes. At current wellhead prices, royalties vary from about 7 percent for new, deep wells with low production in certain locations, to about 23 percent for very old, medium-production, shallow wells in other locations. Royalties on gas produced from these same wells increase to 10 percent and 34 percent, respectively, at gas prices equal to $5 per thousand cubic feet. Until June 1, 1988, the royalty system levies higher royalties on gas that is less costly to produce or recently drilled.

  Effective June 1, 1988, British Columbia has proposed eliminating the current system and implementing a 15 percent royalty for all natural gas when prices are below C$50 per thousand cubic meters (C$1.41/mcf). This royalty rate increases gradually to 25 percent for nonassociated gas, and ranges from 9 to 15 percent for *conservation* (associated) gas. At current wellhead prices of C$1.75 to C$2.50, the new system will impose lower royalty rates of 9 to 11 percent for associated gas and higher royalty rates of 17 to 19 percent for nonassociated gas production. The new gas royalty system increases rates gradually with prices, but no longer distinguishes between old gas and new gas.

  A 1-year natural gas royalty holiday was granted in British Columbia for exploratory wells drilled outside established field boundaries between June 1987 and June 1990 (only until June 1989 in the Fort St. John area). Deep wells drilled into or below the Mesozoic geologic interval receive longer holidays of between 18 to 36 months. Currently, there is no monetary limit on this royalty holiday.

  A *gas cost allowance* can be deducted from the wellhead selling price of the natural gas before computing the amount of the royalty payable. Currently this amount is set by law at C$ 0.20 per thousand cubic feet regardless of actual costs. This allowance is less favorable than Alberta's. However, effective June 1, 1988, British Columbia has proposed to raise its gas cost allowance for all varieties of natural gas. After June 1, 1988, four categories of associated (conservation) gas will be allowed a fixed gas cost allowance of C$16 per thousand cubic meters (C$0.45/mcf).Two categories of low-sulphur nonassociated gas will be allowed gas cost allowances of C$9 and C$13 per thousand cubic meters(C$.26/mcf and C$0.37/mcf). Two categories of high-sulphur nonassociated gas will be allowed gas cost allowances of C$11 and C$20 per thousand cubic meters(C$0.31/mcf and C$0.57/mcf). There is a minimum royalty payment required of 5 percent computed without regard to the gas cost allowance.

The Province of Saskatchewan has enacted royalty holidays for certain exploratory and developmental oil wells and has enacted royalty relief for waterfloods and enhanced oil recovery projects. Saskatchewan is estimated to produce 15 percent of Canada's crude oil and 2 percent of its natural gas. Like the other Provinces, Saskatchewan has adopted incentives for oil and gas production. These incentives include royalty holidays for exploratory and developmental wells and special royalty treatment for EOR projects. However, Saskatchewan like British Columbia, has no royalty tax credits for oil or natural gas.

- **Saskatchewan's Crude Oil Royalty Provisions.** Saskatchewan has the highest royalty rates of the three major producing Provinces. The rates in Saskatchewan vary with both production volumes and wellhead prices. The rates are 30-35 percent for the highest volume wells, 5-30 percent for wells producing between 5 and 45 barrels per day, and essentially zero for stripper wells producing less than 5 barrels per day. Saskatchewan's royalties vary significantly with changes in prices above $10 a barrel. Saskatchewan also allows a 5 percent lower rate for heavy oil.

  Saskatchewan enacted a 3-year royalty holiday for qualified exploratory wells located at least 3 km away from other wells, or producing from depths below all other wells within a 3 km radius. A 5-year royalty holiday applies to qualified exploratory wells drilled in formations older than the Mississippian and able to produce from depths greater than 1700 meters (approximately 5600 feet).

New developmental and infill wells (additional wells drilled in a developed oil field) drilled between January 1, 1987 and June 30, 1988 qualify for a 3-year royalty holiday. Wells drilled thereafter qualify for a 2-year holiday which will remain in effect until oil prices stabilize above $20 (U.S.) a barrel.

In Saskatchewan, enhanced oil recovery projects are entitled to special royalty treatment, as in the other Provinces. Incremental oil production from a new or expanded waterflood project is entitled to the same royalty holiday as developmental wells. Other more expensive EOR projects receive royalty rates as low as 5 percent of gross revenue over the entire life of the project.

- **Saskatchewan's Natural Gas Royalty Provisions.** Saskatchewan also has the highest natural gas royalty rates of the three major producing Provinces. The rate is 30-35 percent for wells producing over 600 thousand cubic feet per day and varies from zero to 30 percent for lower volume wells. The natural gas royalty varies significantly with price. Royalty rates on old gas (pre-1974) are about 10 percent higher.

  Saskatchewan has fewer natural gas royalty incentives then Alberta or British Columbia, since it has relatively little natural gas production. It has no royalty holidays, tax credits or other incentives. There is, however, a natural gas resource allowance of $0.28 per thousand cubic feet.

The United States Royalty System

The U.S. royalty system differs from the system in Canada and many other countries in that royalties are paid primarily to private landowners rather than to the government. In the United States, there remains a substantial amount of production on government-owned lands for which royalties are paid to the Federal, State or local governments. It should be noted that royalties, like severance taxes, are paid on gross revenues rather than on net income, and are therefore regressive. As crude oil and natural gas prices decline, a greater percentage of the net income from U.S. oil and gas investments is paid out in royalties.

Most crude oil and natural gas royalties in the United States are paid to private landowners and range from 12.5 to 25 percent of total revenues. In the lower-48 States, crude oil and natural gas are produced predominately on land owned by private citizens. Producers negotiate with private landowners or with brokers to lease the mineral rights to the land. Historically, royalties paid to private landowners were 12.5 percent of gross revenues. However, in recent years a 12.5 percent royalty is the exception rather than the rule. Today, royalties are typically 18.75 percent in developed fields. Royalties also can be higher, if the lease passes through more than one broker. Normally, each broker will keep an *overriding* royalty share of the producer's revenues from a particular property. The total of the landowner's royalty and the brokers' overriding royalties can, together, reach as high as 25 percent of total crude oil and natural gas revenues.

When oil prices were higher in the early 1980's, the average royalty burdens on newly acquired leases often reached levels as high as 25 percent, but since the price collapse, royalties range between 12.5 and 20 percent.

Royalties also are paid to the U.S. Federal and State governments when crude oil or natural gas is produced on government lands. The U.S. Federal Government receives royalties on crude oil and natural gas produced on Federal lands (including the Outer Continental Shelf) and collects royalties on behalf of Indian Tribes. Production on Federal and Indian lands accounts for about 20 percent of total U.S. crude oil production and 30 percent of total natural gas production. Federal and Indian onshore production accounts for 5-6 percent of total U.S. crude oil and natural gas production, while Federal offshore production accounts for 12 percent of total U.S. crude oil production and 23 percent of total U.S. natural gas production. Royalties vary from lease to lease but average from 12.5 to 16.67 percent of revenues.

For onshore lands, the Federal Government shares 50 percent of the royalties with the State (except in Alaska, where the State traditionally receives 90 percent of royalties.) In offshore Federal waters, the State generally receives 27 percent of royalties for production from leases located in the first 3 miles offshore.

In the Department of Energy's report ,*Energy Security: A Report to the President of the United States*, one of the options considered was a royalty holiday for oil and gas production on Federal lands. The option was not accepted because of the resulting loss of revenues to the Federal Government and because of the uneven impact of the measure on different companies, depending on whether they produce oil from Federal lands. Another option considered in the report – a reduction in the minimum bid for Federal offshore leases from $150 to $25 per acre – has been implemented by the Department of the Interior.

Production of oil and gas from State lands generates royalties for the State. Alaska, the State with the largest amount of production on State lands, collects 12.5 percent of revenues from production of most of its oil fields, including the prolific Prudhoe Bay reservoirs. A survey of several important southwestern U.S. crude oil and natural gas producing States– Louisiana, Texas, Oklahoma, and New Mexico – indicates that royalties vary from 12.5 to 25 percent on State lands.

Table 1. U.S. and Canadian Tax and Royalty Provisions

(Current advantages vs. other country shown in ***bold***)

United States	Canada
No comparable provision.	National Energy Plan: Provided large incentives for exploration and development of frontier oil and gas resources. Eliminated in 1985/86.
Windfall Profit Tax: The WPT imposes a tax up to 70% on domestic crude oil.	No comparable provision. ***In 1986, Canada repealed the Petroleum and Gas Revenue Tax, its equivalent to the WPT (covering both oil and gas).***
Percentage Depletion Allowance: Independent oil and gas producers may use 15% depletion allowance (excess over cost of property is subject to alternative minimum tax). Integrated producers use cost depletion.	Canada repealed percentage depletion in 1984. Lease acquisition costs may be recovered using 10% declining balance method — "earned depletion" is allowed for EOR projects.
Recovery of Exploratory Drilling Costs: Dry hole costs are expensed in first year. For successful wells, independent oil and gas producers may expense IDC's in first year (excess over 65% of net income subject to AMT) — majors allowed to expense only 70% of IDC's.	Recovery of Exploratory Drilling Costs: All drilling costs fully expensed in first year. For integrated companies, this is slightly more favorable than in United States.
Recovery of Developmental Drilling Costs: Independents expense IDC's (subject to AMT) — integrated companies expense 70% of successful IDC's.	Recovery of Developmental Drilling Costs: All producers use a 30% declining balance method.
No comparable provision.	***Exploration and Development Drilling Credits for Oil and Gas:*** Federal government provides cash refunds for 1/3 of exploratory and developmental drilling costs up to $10 million (Canadian);reduced to 1/6 from 10/88-12/89. Exploratory drilling refunds of 30%(CEIP) starting 10/88.
Accelerated Depreciation of Equipment: Expenditures for drilling and lease and well equipment recovered using accelerated depreciation over 5 or 7 year periods using 28% or 40% (double) declining balance methods.	Depreciation of Equipment: calculated using a slightly less favorable method (25% declining balance method).
Geological and Geophysical Cost generally are recovered over expected life of property.	***Geological and Geophysical Costs:*** expensed in first year.
Corporate Tax Rate: 34%.	Corporate Tax Rate: 35% plus surcharge (3% of 35%). After tax reform reduced to 28% plus surcharge.
Deductible State Taxes: Average severance taxes of 5-7% and income taxes of 7% — deductible against Federal tax. Many States have reduced severance taxes for marginal and EOR wells.	Non-deductible Provincial Income Taxes: 15% in Alberta — not deductible against Federal income tax. However, resource allowance of 25% of net income is deductible from Federal tax.
Royalties: Royalties, which are largely paid to private landowners, generally have not been reduced. The Federal government has reduced its minimum bid for offshore lands from $150 to $25.	***Royalty Holidays***: Alberta provides one to five year royalty holidays for certain oil and gas discoveries certified since 9/86. Dollar limitations apply, and holidays phase out in 1989. Additional incentives for deep gas and EOR. Other Provinces have similar programs.
No comparable provision.	***Royalty Tax Credits***: Alberta offers refundable income tax credits for 75% of Provincial royalties (up to $C 3 million per taxpayer per year).

Table 2: A Comparison of Oil Royalties & Taxation in Canada's Three Main Producing Provinces

<table>
<tr><th>ALBERTA
81% of Oil Prod.</th><th>BRITISH COLUMBIA
3% of Oil Prod.</th><th>SASKA TCHEWAN
16% of Oil Prod.</th></tr>
<tr><td colspan="3">AVERAGE ROYALTY RATES</td></tr>
<tr><td colspan="3">For large volume wells (>100 bbls./day) and current wellhead prices ($20.00 Canadian):</td></tr>
<tr><td>25-28%</td><td>25-28%</td><td>32-35%</td></tr>
<tr><td colspan="3">For medium volume wells (20 to 100 bbls./day) and current wellhead prices:</td></tr>
<tr><td>9-25%</td><td>9-25%</td><td>23-32%</td></tr>
<tr><td colspan="3">For small volume wells (1 to 20 bbls./day) and current wellhead prices:</td></tr>
<tr><td>1-8%</td><td>1-8%</td><td>0-23%</td></tr>
<tr><td colspan="3">Alberta and British Columbia have essentially equivalent royalties; Saskatchewan has higher royalties. Higher wellhead prices raise royalty rates only slightly, but lower prices reduce royalties about 1% per $1.00 Canadian. Old oil (pre-1974 in Alberta and Saskatchewan, pre-1976 in B.C.) has royalties averaging about 5 to 8 percent higher for medium and large wells. Small producers of old oil pay royalties that are about 8 percent higher in B.C., but only slightly higher in Saskatchewan and Alberta.</td></tr>
<tr><td colspan="3">CRUDE OIL ROYALTY HOLIDAYS
"Royalty holidays" are set periods of time when no Provincial royalties are collected</td></tr>
<tr><td colspan="3">Exploratory Wells</td></tr>
<tr><td>For new or deepened expl. wells drilled in unproven areas the following royalty holidays:
From 10/86 to 10/87, 5 yrs.
From 11/87 to 10/88, 3 yrs.
From 11/88 to 10/89, 1 yr.</td><td>From 7/85 to 6/89, exploratory wells drilled at least 7 km from producing wells or deeper than all nearby wells qualify for a 3-year holiday.</td><td>Currently, exploratory wells at least 3 km from producing wells or deeper than all nearby wells get a 3-year holiday. Some deep wells get 5 years</td></tr>
<tr><td colspan="3">Development Wells</td></tr>
<tr><td>NONE</td><td>From 7/85 to 6/89 new development and infill wells are exempt from royalties for 2 years.</td><td>New devel. and infill wells drilled in areas with no other devel. wells receive holidays:
From 1/87 to 6/88, 3 yrs.
From 7/88 to 6/89, 2 yrs.
From 7/89 until $20 crude returns, 2 years. Also, until 7/89: new wells drilled in established areas may receive year. Some deep wells get 3 yrs</td></tr>
<tr><td colspan="3">ENHANCED OIL RECOVERY ROYALTY RELIEF</td></tr>
<tr><td>Operator can deduct approved EOR costs before calculating royalties if the amount of Provincial royalties paid on the EOR field's production is not less than royalties paid before the start of EOR.</td><td>Incremental Production from experimental EOR projects are exempt from royalties. Other EOR projects are only allowed lower royalty rates. Waterflood projects receive 2-yr. holidays. All incremental oil is subject to more favorable royalty rates.</td><td>EOR projects pay the lesser of 5% of gross revenue or 10% of operating revenue before payou and the greater of 5% of gross revenue or 30% of net revenue after payout. Incremental production from new waterfloods qualifies for royalty holidays.</td></tr>
<tr><td colspan="3">ROYALTY TAX CREDITS</td></tr>
<tr><td>75% Royalty Tax Credit to a maximum of C$3 million per taxpayer per year. Proposed reduction to 50% with a maximum of C$2 million.</td><td>NONE</td><td>NONE</td></tr>
<tr><td colspan="3">PROVINCIAL TAXES</td></tr>
<tr><td>14% of Net Corporate Income</td><td>15% of Net Corporate Income</td><td>17% of Net Corporate Income
(15% after Jan. 1, 1989)</td></tr>
</table>

Table 3: A Comparison of Natural Gas Royalties and Taxation in Canada's Three Main Producing Provinces

ALBERTA 87% of Gas Prod.	BRITISH COLUMBIA 10% of Gas Prod.	SASKATCHEWAN 3% of Gas Prod.
Average Royalty Rates		
For large volume wells (>600 mcf/day) and current wellhead prices($2.00 Canadian):		
25%	**18% (10% for associated gas)**	**28-32%**
For medium volume wells (150 to 600 mcf/day) and current wellhead prices:		
15-25%	**18% (10% for associated gas)**	**15-28%**
For small volume wells (0 to 150 mcf/day) and current wellhead prices:		
5-15%	**18% (10% for associated gas)**	**0-15%**
Higher wellhead prices will increase the above royalty rates1-3% per $1.00 Canadian. Old gas (pre-1974 in Alberta, pre-October 1976 in Saskatchewan) has royalties averaging about 7 to 10 percent higher for medium and large volume wells. Small volume old gas wells are taxed slightly higher in Saskatchewan and Alberta. British Columbia as of 6/1/88 will no longer consider age or well production in determining royalties.		
NATURAL GAS ROYALTY HOLIDAYS		
"Royalty holidays" are set periods when no Provincial royalties are collected.		
	Exploratory Wells	
Exploratory wells drilled in unproven areas or deeper than all other wells in proven areas qualify for a one year holiday or equivalent royalty credits (max. limit/well/year of C$ 2 million).	Exploratory wells drilled outside of existing fields from 6/87 to 6/90 a one year holiday. No dollar limitation.	NONE
	Deep Gas Wells	
New or deepened expl. wells drilled below 2500 m qualify for a dollar based royalty credit that increases with depth with a max. limit/well/year of C$ 3.6 million)	From 6/87 to 6/90 a 18 to 36 month holiday for Mesozoic or pre-Mesozoic deep wells. Wells in less explored areas get longer holidays. No dollar limitation.	NONE
GAS COST ALLOWANCE		
A " gas cost allowance" is subtracted from wellhead selling price before royalty is calculated. This allowance is calculated in Alberta and set by law in the other Provinces.		
appr. C$0.54/mcf	**associated gas C$0.45/mcf** **nonassociated gas C$0.25 - 0.57/mcf**	**C$0.28/mcf**
ROYALTY TAX CREDITS		
A 75% royalty tax credit is allowed against Provincial income taxes to a maximum of C$3 million per taxpayer. Proposed reduction to 50% with a maximum of C$2 million.	NONE	NONE
PROVINCIAL TAXES		
14% of Net Corporate Income	**15% of Net Corporate Income**	**17% of Net Corporate Income** **(15% after Jan. 1, 1989)**
A small portion of royalties in excess of the Federal resource allowance is deducted in all Provinces.		

APPENDIX

DESCRIPTION OF AN ONGOING ANALYSIS OF THE IMPACTS OF TAX AND FISCAL SYSTEMS ON THE COMPETITIVENESS OF INVESTMENTS IN U.S. OIL AND GAS EXPLORATION AND PRODUCTION

This working paper compares the statutory provisions of the U.S. and Canadian tax and fiscal systems. Calculations of discounted rates of return from oil and gas investments in each country were used to verify the results of the statutory analysis. However, to address accurately the issue of whether there is a *level playing field* among competing countries for the capital to develop natural resources, particularly oil and gas, a more sophisticated quantitative analysis is necessary and has been initiated. Preliminary results should be available by the end of 1988.

The United States and many other industrialized countries have changed their tax codes. There are many provisions within the U.S. tax and fiscal systems that affect the actual and expected after-tax return from U.S. oil and gas investments. Additionally, the relative economic impact of tax and fiscal systems must be made within the context of each country's geological resource base. Since the United States is a mature geological province, this fact must be considered when analyzing whether the United States tax and fiscal system is competitive in attracting capital to develop remaining U.S. reserves.

A. Measuring the competitiveness of tax and fiscal systems.

Investments in U.S. oil and gas production must compete for capital on two separate levels. Domestically, companies and individuals that do not have the capital, expertise, or the size to compete outside the *lower 48* still must compete for investment capital with all other domestic investments. These investments offer differing after-tax rates of return discounted by the inherent risk of the investment medium. Internationally, foreign countries use their tax and fiscal systems to compete against the U.S. for the capital to invest in natural resource development. An analysis and comparison of the relative economic impacts of the U.S. tax and fiscal system will measure the competitiveness of the U.S. system and help to identify those provisions that could enhance U.S. competitiveness.

In order to quantitatively measure the competitiveness of the U.S. tax and fiscal systems, the marginal, effective, and total rates of "take" within the United States must be developed and compared with the "take" within other countries. The analysis should include an evaluation of the effectiveness and the after-tax values of specific tax and fiscal provisions intended to encourage resource development both in the U.S. and abroad. It also is necessary to compare the degree to which U.S. and foreign systems share the risks inherent in natural resource development, as well as the value of that resource development to society.

This analysis should then identify and compare those specific provisions of tax and fiscal systems that distort microeconomic decisionmaking in a manner inconsistent with stated public policy.

B. An analysis of tax and fiscal systems must include all forms of "take" from the revenues of oil and gas production.

A division of revenues from oil and gas production in the United States occurs among four participants: the landowner, the State and Federal governments, and the investing company or individual. The relative division affects significantly the rate of return on investments in U.S. oil and gas production.

On both private and public lands, the landowner's *take* of revenue is in the form of lease bonuses and royalties. Bonuses are paid before hydrocarbons are produced from a property. Royalties normally *take* a portion of the gross revenues from production. Similarly, states *take* revenues from oil and gas production in the form of severance taxes and, in some cases, income taxes. The U.S. and foreign governments *take* revenues from oil and gas production in the form of lease bonuses and royalties as well as income, excise and/or severance taxes. The taking of revenues from oil and gas production affects significantly the rate of return on investments in natural resource development.

The major provisions of the regular U.S. income tax system affecting oil and gas production are the tax rates and the direct and indirect cost recovery provisions. Cost recovery provisions specifically affecting oil and gas investments in the United States include percentage and cost depletion, depreciation, and deductions for the recovery of intangible drilling cost (IDC's), geological and geophysical expenses, and interest expenses. Additionally, there are provisions limiting the utilization of net operating losses, passive losses, depletion, tax credits and IDC's that affect investments in U.S. oil and gas production.

In addition to the regular income tax system, the United States has an alternative minimum tax system (AMT). A number of AMT provisions affect directly and indirectly investments in U.S. oil and gas production. These provisions add back to regular taxable income, the amount of percentage depletion deductions in excess of the adjusted basis of a property, the amount of accelerated depreciation in excess of amortization; and the amount of IDC's expensed in excess of 10 year straight-line amortization to the extent this exceeds 65% of taxable income.

Interaction between the provisions of the regular U.S. income tax code and the AMT can affect total, effective and marginal rates of take in ways that may not have been intended and that may effect the competitiveness of investments in U.S. oil and gas production. The ongoing quantitative analysis will review the impacts of these individual provisions as well as their cumulative effects and interactions.

C. A competitive tax and fiscal system will maximize natural resource development in a cost effective manner.

The competitiveness of a country's tax and fiscal system is inextricably tied to its underlying geology. The United States is a mature petroleum province in which three fourths of the world's wells have been drilled and in which its crude oil wells produce an average of 13.9 barrels per day. This compares with 42 barrels per day per well in Canada, 650 barrels per day in Mexico and 7000-13000 barrels per day in Saudi Arabia. It should be noted that 74 percent of all U.S. wells produce an average of only 2.67 barrels per day. In 1986 alone, 95,000 wells (15 percent of all U.S. wells) stopped production. In 1987, the U.S. spent $45 billion dollars on imported crude oil. In 1995, the U.S. is projected to spend over $100 billion.

Oil production in the United States has declined by approximately 800,000 barrels per day since 1985 . Current production is approximately 8.3 million barrels per day. By 1995, U.S. production is projected to drop to 5.3 million barrels per day, unless prices rebound significantly. The probability for finding large new deposits of oil is low. Many promising unexplored areas tend to be in remote or hostile environments, and will likely be expensive to produce and subject to long lead times . These factors affect the effective, total and marginal rates of take from U.S. oil and gas production, and can affect whether capital will be invested in developing these resources.

Future oil production in the U.S. is likely to come from maximizing production from existing fields. Over 75 percent of new oil reserves added in the last decade in the U.S. have come from extending old reservoirs, finding new reservoirs in old fields, and the application of secondary recovery methods. These methods attempt to produce what is called *mobile oil*, oil that will flow freely if a pathway is provided. Other more advanced techniques try to produce the remaining immobile oil by changing its temperature or composition. These methods are generally called enhanced oil recovery methods or EOR. Secondary recovery and EOR are likely to be the primary sources of new oil in the 1990's. The ability of the U.S. to compete for capital to invest in secondary and EOR production will, in significant part, be determined by the competitiveness of its tax and fiscal system.

QUESTIONS FROM SENATOR BINGAMAN

Ensuring Equal Footing for Domestic Producers

Question 3:	Are any steps being taken to ensure that domestic natural gas producers are competing on an equal footing with foreign producers?
Answer:	There are several different mechanisms and channels for resolving disputes regarding competitive issues between domestic and foreign producers, e.g., DOE's authority over imports and exports of natural gas, FERC's authority over interstate natural gas pipeline rates and construction of facilities used to transport imported and exported gas, the Free Trade Agreement's dispute resolution mechanisms, and the mechanisms under the General Agreement on Tariffs and Trade for redressing unfair trade practices. In addition, DOE intends to evaluate any concerns about the competitiveness of the domestic gas industry in the context of developing a National Energy Strategy. The gas market is evolving and fast changing. Many of these changes will have impacts that deserve DOE's attention. We encourage the affected parties to bring both

general and specific concerns and impacts to our attention.

QUESTIONS FROM SENATOR BINGAMAN

New Gas Markets: How Big?

Question 4(A): The prospect of new markets for natural gas in the 1990s has received a great deal of attention. It is predicted that demand for natural gas for environmental compliance and for new electric power generation as well as the expansion of pipeline capacity into the Northeast and California all represent opportunities to expand markets for natural gas.

Has the Department of Energy quantified the size of these anticipated markets?

Answer: By the year 2000, the Energy Information Administration (EIA) projects that annual consumption of natural gas will climb to slightly more than 20 trillion cubic feet per year, or about the same as it had been in 1979. These projections (published by the EIA in the Service Report, *Electricity Generation from Natural Gas: Prospects and Implications for the United States January 1989*) take into account all legislation which is currently in place but do not project the impact of any legislative or regulatory changes under consideration.

The electricity sector is expected to be the fastest growing market for natural gas. By the year 2000, the United States may be using about twice as much natural gas to generate electricity as it does now. It is estimated that utilities consumed 2.8 trillion cubic feet of natural gas in 1988. In 2000, the projected annual consumption of gas by electric utilities ranges from a low of 4.6 trillion cubic feet to a high of 6.6 trillion cubic feet.

Industrial sector activities account for the largest share of gas used in this country, a portion of which is used for electricity generation. This sector will continue as the largest sector through 2000, although the industrial share will shrink slightly. Total industrial use by 2000 is forecast to be about 6 trillion cubic feet. Using the most current historical data for 1988 (updated since the publication of the Service Report), this indicates a decline of about 6% from 1988. This reflects the outcome of two divergent trends: declining gas use in manufacturing activities and rising use in cogeneration activities.

Appendix C in the EIA Service Report, Electricity Generation from Natural Gas: Prospects and Implications for the United States provides a summary of regional demand by sector for three gas use scenarios. A copy of that Appendix is attached.*

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*Subcommittee Note.--The EIA Service Report has been retained in Subcommittee files.

QUESTIONS FROM SENATOR BINGAMAN

Question 4(B):	Has the Department of Energy ascertained the time frame within which these markets are expected to materialize?
Answer:	The time frame under which these markets may materialize is a function of the economic conditions facing the end-users. GNP growth, oil prices and gas resource levels are all crucial assumptions regarding the timing of any expansion of these markets. Still, for electric utilities, the capability to build small gas plants with a short-lead time makes gas an attractive option. In addition, gas is available today at relatively low prices. Recent changes in laws and regulations have favored gas-fired plants. As mentioned in the EIA Service Report indicated above, gas use for electricity generation will increase in existing gas-fired steam plants in the early 1990's as electricity demand grows and coal and nuclear plants become fully utilized. In the mid to late 1990's, utilities are expected to add new combined-cycle plants and, to a lesser extent, combustion turbines that

burn natural gas. In addition, non-utilities (mostly cogenerators) are projected to use more natural gas in new plants that are built. Gas use to generate electricity by non-utilities is expected to grow from 337 billion cubic feet in 1988 to 683 billion cubic feet by 2000.

QUESTIONS FROM SENATOR BINGAMAN

Cofiring Technologies

Question 5:	Please detail for the Subcommittee the analysis that the Department of Energy has done, or plans to undertake, regarding the role that cofiring technologies can play as part of a coordinated energy and environmental policy.
Answer:	Natural gas cofiring of coal-fired boilers, combining as it does two of our most important domestic fuel resources, can potentially play a big role in a coordinated energy and environmental policy. Demonstration of this technology will provide additional options for coal users in alleviating the adverse environmental impacts of coal utilization and thus can contribute to the preservation of existing coal markets. Conventional cofiring using existing burners can reduce SO_2, NO_x, particulate, and CO_2 emissions by 10%-25%. Boiler fouling and slagging is also reduced. A specialized version of cofiring is reburning technology. In this case, a small amount (approximately 10% - 20% of the energy input) of

natural gas is introduced above the primary combustion zone followed by additional burnout air. This approach offers the potential of up to 80% NO_x reduction and 20% SO_2 reduction in addition to the benefits previously cited.

QUESTIONS FROM SENATOR BINGAMAN

Cofiring Technologies

Question 6: What has the Department of Energy done to promote the demonstration and deployment of cofiring technologies?

Answer: With respect to simple cofiring, the Department has done very little development in the past. Private industry has conducted a demonstration of the technology. The Department has concentrated its efforts on the more complex and potentially more advantageous staged combustion process known as gas reburning (a staged combustion process specifically aimed at controlling high percentages of oxides of nitrogen).

With respect to simple cofiring, the Department believes that it has the potential to reduce SO_2, NO_x, particulate, and CO_2 emissions by 10-25% and can be an important option for utilities having to control these pollutants. In specific cases, it may be an attractive alternative compared to switching to low sulfur coal or other fossil fuels. In addition, the technology may reduce operating costs by a small amount by reducing the rate of boiler slagging and fouling. Consequently, the Department is presently negotiating a contract to cosponsor a cofiring project that will be undertaken by the Southern Indiana Gas and Electric Company in a large coal-fired powerplant in southern Indiana. This project coupled with data already available on cofiring, it is believed, will demonstrate the potential of this technology, both to control pollutants and to improve the operability of the plant.

With respect to the more complex gas reburning, the Department is supporting a demonstration of the technology under the Clean Coal Technology Program. This is the Energy and Environmental Research Corporation (EER) project on enhancing the use of coals by gas reburning - sorbent injection. The project demonstrates gas reburning for NO_x control along with sorbent injection for SO_2 control (GR/SI) on two different boiler configurations (cyclone and tangentially fired). These units are 40 MWe and 80 MWe, respectively. A third configuration (wall-fired) is covered under project scope but funding limitations presently preclude the testing of a wall-fired unit.

The EER project has currently completed detailed design and long-lead equipment procurement for construction. Phase II construction is pending the completion of host site agreements.

The FY90 appropriation includes $2.5 million for DOE to participate in a gas reburning project at the Ohio Edison plant in Niles, Ohio.

QUESTIONS FROM SENATOR METZENBAUM

Pipelines' Obligation to Serve

Question 1: Your testimony advocated deregulation of pipelines' gas sales function so that they are able to compete with unregulated gas marketers, brokers, and producer-aggregators. If Congress were to mandate this change, how would it affect the pipelines' statutory obligation to serve their customers?

Answer: Our testimony stated that "[a]s we become more confident that we have worked out the kinks in open access, we should closely examine whether consumer interests...are being served by continued federal regulation of the prices charged by interstate pipelines for natural gas."

It is not clear what effect the deregulation of natural gas pipelines' gas prices would have on the pipelines' "obligation to serve." The "obligation to serve" itself is extremely difficult to define. It has not prevented pipelines from curtailing their customers when supplies were not available because prices were regulated at levels below market prices. Nor has it prevented consumers from being served with natural gas at prices well above market prices.

The Department believes that both consumers and pipelines will be better off if LDC's acquire the supplies that they need from pipelines just as LDC's acquire natural gas from other suppliers through the negotiation and execution of contracts rather than under Federal rules and regulations.

QUESTIONS FROM SENATOR METZENBAUM

Reconciling Obligation to Serve with Competition

Question 2: How could this conflict between the obligation to serve customers and the need for fair competition between sellers of gas be reconciled?

Answer: As noted above, it is not clear that there is really a conflict or that the obligation to serve has benefited customers. It has not prevented curtailments and above-market prices for many customers. The Department believes that competition among all sellers of natural gas will better serve consumers than assigning to one class of natural gas sellers some special "obligation to serve." There is no more need to require pipelines to sell natural gas as a commodity to their customers than there is to require the C&O Railroad to sell coal to its electric utility customers.

QUESTIONS FROM SENATOR METZENBAUM

Different Abandonment Rules for Sales and Transportation

Question 3(A): A problem for consumers' security of supply has arisen since the industry trended towards transportation of customer-owned gas. When certificated pipeline sales dominated the market, pipelines were obligated to provide service, even if service agreements between pipelines and local distribution companies had expired. FERC's new firm transportation certificates include pre-granted abandonment of the obligation to serve customers at the end of the transportation contract term. As such, firm transportation service becomes inferior to traditional pipeline sales service.

How does DOE propose to remedy this problem?

Answer: The Department does not believe that the "trend toward transportation" has created a problem. The Department regards this trend as a healthy, and essential institutional development if natural gas is to realize its potential in national energy and environmental policy.

Having different rules for sales service and transportation service, on the other hand, does create a problem. The Department's view of the potential for natural gas is predicated on level playing field competition for sales and transportation. Usually, different rules for sales and transportation means one service will be superior to the other. This may create harmful distortions in the market.

The problem you refer to is a good example. If the abandonment rules are different between these services, it may force distribution companies to choose sales over transportation service. This thereby deprives these companies, and the residential and commercial customers they serve, of some of the benefits of competitively priced gas. Accordingly, the Department is concerned that the different rules for sales and transportation abandonment may distort the development of a competitive market for natural gas.

To rectify this distortion, the Department believes the transportation rule should apply to sales. As we have discussed, there is no reason to believe that parties in this mature natural gas industry cannot, and should not, be responsible for buying and selling gas on the same commercial basis that governs every other commodity. When a contract expires, the parties' obligations under the contract expire. To allow one party, but not the other, to treat the contract as if it continues, is fundamentally unfair and contributes to the kinds of distortions in the natural gas market that we have seen over the last decade.

Railroads are not "obligated to serve" utilities with coal. Nor are petroleum pipelines or barges "obligated to serve" utilities with oil. We know of no good reason why natural gas should be treated differently.

QUESTIONS FROM SENATOR METZENBAUM

Question 3(B): How should local distribution companies overcome the conflict between the inferior security of firm transportation with the continuing obligation of LDC's to serve their captive customers as scrutinized closely by state utility commissions?

Answer: It is not clear to us why limiting the obligation of a pipeline to provide firm transportation service to the contract obligations agreed on by the pipeline and an LDC provides "inferior security of firm transportation." In order to serve their customers, LDC's should do what most are doing: developing a flexible portfolio of gas supply contracts, some short-term, some long-term, to meet their needs. Similarly, LDC's are contracting with pipelines for the levels of firm and interruptible transportation services they need. The challenge is always to reach the proper balance. Long-term, secure supply and firm capacity arrangements are available, but they cost more (as they should) than relying on the spot market for gas purchases or on interruptible capacity for transportation.

QUESTIONS FROM SENATOR METZENBAUM

Eminent Domain and Environmental Considerations

Question 4(a): Your testimony criticizes the protracted pipeline licensing process and points to oil pipelines as an example of the feasibility of streamlining or eliminating federal construction approvals. You argue that this change would facilitate pipeline construction where and when it is needed. Under the Natural Gas Act, FERC can only delegate the sacred right of eminent domain to pipeline applicants after thorough economic, technical and environmental analyses to insure that the proposed facilities "are required by the public convenience and necessity."

Shouldn't any deregulation proposal for pipeline construction procedures also remove the grant of federal eminent domain?

Answer: It is too early to say what the contours of any deregulation proposal will be. At this point, however, it is useful to look at the oil pipeline analogy and ask how that industry operates.

Oil pipelines do not need a certificate of public convenience and necessity from any federal entity. Although there is no federal eminent domain for oil pipelines, oil pipelines obtain eminent domain at the state level. This system appears to work reasonably well, but we continue to study these issues.

QUESTIONS FROM SENATOR METZENBAUM

Question 4(B): How would you reconcile expedited procedures with NEPA requirements?

Answer: Again the contrast with oil pipelines is instructive. The National Environmental Policy Act (NEPA) is triggered only by "major federal actions significantly affecting the quality of the human environment." Because federal certification is not needed to construct new facilities and if federal land is not involved, oil pipelines are not required to comply with NEPA. Oil pipelines may, of course, be required to obtain permits at the state level and adhere to applicable state environmental regulations. In some instances, oil pipelines have been blocked by state concerns. On balance, however, the oil pipeline industry seems to be able to build needed capacity to serve additional customers in an environmentally responsible manner, yet in a more timely and efficient way.

McKinsey & Company, Inc. 1700 PENNSYLVANIA AVENUE, N.W. WASHINGTON, D.C. 20006 TELEPHONE 202-662-3100

October 17, 1989

Mr. Don Santa
Subcommittee on Mineral Resources
Development and Production
U. S. Senate
Room 364
Dirksen Senate Office Building
Washington, D.C. 20510-6150

Dear Don:

Attached are my responses to the questions raised at the oversight hearings. I enjoyed the opportunity to testify and hope you find the enclosed helpful.

Best regards,

John C. Sawhill

Enclosure

RESPONSES TO FOLLOW-UP QUESTIONS

TO THE SEPTEMBER 26 OVERSIGHT HEARING

John C. Sawhill

Have natural gas producers come to rely too much on the spot market in lieu of purchases under long-term contracts?

> Yes. Many local distribution companies are buying 30 to 50 percent of their supply under short-term spot market purchases - typically contracts that are in force for 30 days. While there is a place in every distributor's supply portfolio for these 30-day purchases, 30 - 50 percent is too high a proportion for most distributors. In my view, short-term purchases by distributors should not be significantly greater than the proportion of a distributors' sales accounted for by industrial customers with the capability to switch quickly from natural gas to alternative fuels such as residual fuel oil. To the extent spot purchases exceed sales to customers with switching capability, a distributor is supplying a long-term market with short-term gas. This mismatch raises the possibility that, if the spot market shrinks quickly, distributors will have to scramble for supply and, because of market disruptions, may not be able to fulfill their contractual commitments.

What are the likely consequences should this level of reliance on the spot market continue for much longer?

> An overreliance on the spot market could lead to sharper price increases and greater likelihood of supply cutoffs for certain customers. In a future cold winter, spot prices could rise rapidly, causing distributors to switch back to purchases from pipelines. However, because so many of their customers are relying on spot gas, many pipelines do not have sufficient gas under contract to meet their contractual obligations. They will be forced to buy supply on short-notice. To the extent they are not successful, they may have to curtail some customers. Under any circumstances prices will be driven upward more sharply than they would have otherwise.
>
> Overreliance on spot gas also exacerbates long-term supply pressures. Spot prices currently do not reflect the cost of replacing reserves. Thus there is little incentive for producers to drill for new gas. Under longer-term contracts, producers can shift a portion of the risk associated with future prices to the purchasers of gas. This more economically efficient outcome would spur drilling, thereby easing the transition to a supply-constrained market.

What will it take to get natural gas purchasers to return to longer-term contracts?

There are two policy-related initiatives which could move the gas industry toward more rational, longer-term gas contracts. They are 1) rapid approval and implementation by FERC of gas inventory changes; and 2) relaxation of state public utility commission pressure on utilities to pursue least-cost purchasing without regard to the value of long-term supply.

Inventory changes are helpful because they force distributors to be held accountable for the decision to purchase spot gas. At present, a distributor knows that, even if it purchases spot gas, its pipeline suppliers are contractually obligated to stand ready to meet its needs if spot sellers cannot meet the terms of their contracts. The pipeline is placed in the untenable position of being forced to contract for supply equal to its sales obligations even though its actual sales are likely to be only a fraction of this obligation. Not surprisingly, many pipelines have not maintained supplies under contract equal to their sales obligations. With an inventory charge, the distributor is forced to compensate the pipeline for standing ready to supply gas. Thus the distributor must take into account the risk of purchasing spot gas. The distributor will adjust its sales contract level with the pipeline downward to a level that is likely to reflect its actual purchases from pipelines. The pipeline will then be able to initiate long-term contracts with suppliers that will allow producers to increase drilling activity.

It would also help if state utility commissions moved away from tightly-defined "least-cost purchasing" programs in which the only criteria for evaluating a utility's purchasing action is whether the utility purchased the lowest cost supply available. Explicit recognition by commissions of the importance of security of supply should be made. At this time, there may be frequent occasions when consumers will be better off if distributors do not purchase the least cost supply. If a long-term purchase with strong penalties to the supplier for failure to perform can be made, commissions should expect that distributors will have to pay a premium. Distributors should be encouraged, not discouraged, to pursue such contracts.

In your testimony to the subcommittee, you differ with respect to the elasticity of supply and demand for natural gas and the consequences that this might have. Do you differ with respect to the natural gas policies that the Department of Energy and the Federal Energy Regulatory Commission should pursue in the 1990s? Please specify the policy initiatives that you believe should be undertaken in this era. (Question asked of Ken Lay and John Sawhill)

While I cannot speak for Ken Lay, I think it is safe to say that we are in general agreement with regard to natural gas policy. Certainly, I support increased reliance on market mechanisms rather than government interaction to set prices and allocate supply. Enron's position on key public policy issues related to natural gas suggests that it holds the same view.

With regard to future policy, I believe that the transition to a supply-constrained market will be easier if FERC can move quickly to enact several of the initiatives it has proposed. Most important is the gas inventory charge which, as I said in response to the previous question, is critical to moving distributors away from overreliance on the spot market. FERC should enact long-term (5 to 10 year) inventory charges for the pipelines as soon as possible. Going through another winter with distributors relying on spot purchases and pipelines unable to contract for new supply because of low sales levels is extremely risky. Having capacity brokering in place will also ease the upcoming market transition. It is important for customers to be able to broker spare gas pipeline capacity to the highest bidder in times of supply tightness to assure that resources are allocated in the best way possible.

The two major changes to current regulation that I would like to see are increased deregulation of the pipeline sales function and removal of FERC certification requirements for new pipeline construction. The justification for regulating pipeline gas prices has disappeared with customer access to spot gas. Pipelines should now compete on equal footing with other suppliers and profit or lose money selling gas depending on their skill as a purchaser. In this regard, I do not support efforts by Congress to eliminate certain types of inventory charges. In a market where there are numerous buyers and sellers, a pipeline has every incentive to structure a price formula that will allow it to purchase gas economically. Non-gas transportation rates and the non-gas portion of sales rates should remain regulated.

As for new pipeline construction, FERC has historically determined whether new pipeline projects should be allowed based on a determination of whether a project represented the most economic alternative. In a more competitive market, if a pipeline is willing to spend money on a new project, it should be allowed to go ahead since the pipeline will bear the risk if the market has too much capacity. Regulators can restrict their review to the impact on the environment and to assuring that captive customers do not assume the cost of the new construction.

Response To Follow-Up Questions From Prepared Testimony Presented by Arlon R. Tussing on September 26, 1989 Before the United States Senate Committee on Energy and Natural Resources Subcommittee on Mineral Resources Development and Production

During the past several years, interstate pipelines have released substantial gas reserves that had been dedicated to their system supply. At the same time, these pipelines remain under a service obligation to sell gas to their customer's on demand.

1. What would be the outcome if during a cold snap customers called on pipelines to deliver gas at levels commensurate with the pipelines' service obligations?

   Response:

   There are several actions that can be anticipated and which constitute a reasonable response on the part of pipelines that are unable to meet peak day delivery obligations strictly from the reserves still dedicated to their system gas supply. Pipelines can draw on gas supplies kept in storage and can augment their storage and contract gas supplies with purchases made at competitive prices in the spot market.

   It should also be recognized that those gas supplies previously dedicated to pipelines which have been released are either being sold in the spot market, being shut-in in anticipation of higher prices or being put under new contracts of substantially shorter duration. In other words, the released gas has not disappeared, it is simply being offered under different, more flexible terms to whoever is willing to pay a price acceptable to the seller.

2. What should be done to address the discrepancy between pipelines' service obligation and the actual level of service that customers are willing to purchase?

   Response:

   The pipeline's service obligation should not be viewed as a disembodied responsibility which regulation, or some other institution, has imposed upon the pipeline. A service obligation is the antithesis of an open-ended obligation to serve "on demand" whatever gas requirement a pipeline customer announces it wishes to purchase. Instead, the service obligation that exists between the pipeline and each of its customers is defined contractually, pursuant to the terms of the pipeline's tariff. As such, it is an explicit commitment entered into voluntarily by the parties, and it is both circumscribed and legally enforceable.

If substantive discrepancies exist between the service obligation presently maintained by the pipeline and the service obligation a customer wishes to pay for, there is no reason not to view this as a matter for private contractual negotiation between the parties. The need for such negotiations has been lessened by the sales entitlement conversion option available to the customers of pipelines holding Order No. 500 certificates. To the extent that a pipeline's customer wishes to reduce its sales service entitlement and instead purchase a like amount of transportation service, the conversion option facilitates this substitution, and the pipeline is granted abandonment of the sales obligation that has been converted.

Furthermore, Commissioners at the FERC have recently voiced an intent to restore the sales entitlement reduction option originally contained in Order No. 436, and which was dropped in Interim Order No. 500. Such restoration would further the evolution that is already underway to alter the contractual service obligations of the pipelines to encompass only that single aspect of the industry which is imbued with the public interest --- the physical transportation of natural gas. It would leave to competitive markets, as was intended under the NGPA, the provision of secure gas supplies at reasonable prices, which with open-access to transportation service would be available to all pipeline customers.

NATURAL GAS SUPPLY ASSOCIATION

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Nicholas J. Bush
President

October 24, 1989

Honorable Jeff Bingaman
Chairman
Subcommittee on Mineral Resources
Development and Production
Energy and Natural Resources Committee
United States Senate
Washington, DC 20510

Dear Chairman Bingaman:

The NGSA wishes to thank you for the opportunity to present our views on the supply and deliverability study during the Subcommittee's oversight hearings on September 26, 1989. NGSA remains bullish regarding the amount of natural gas that is available to serve our Nation's needs, as do AGA and INGAA. Nevertheless, as we noted in our testimony, NGSA is concerned about the loss of production in offshore areas due to recently enacted moratoria on offshore leasing. If gas is going to contribute to our current environmental and energy security problems, we must be allowed access to these areas to keep up with the increasing demand for natural gas.

By letter dated October 2, 1989, you asked that we respond to two additional questions. Our answers to those questions follow.

(Q) What would be the outcome if during a cold snap, customers called on pipelines to deliver gas at levels commensurate with the pipelines' service obligations?

(A) Pipelines by their own reports, do not have reserves dedicated to system supply to meet all historic contract demand levels because their previous sales customers have indicated that they want to purchase spot gas. For the market to work in the future, pipelines cannot be held responsible for holding reserves that customers are not required to buy -- or instead purchase on the spot market. If a cold snap occurred, however, pipelines could purchase their gas needed requirements on the spot market to meet customer demand.

(Q) What should be done to address the discrepancy between pipelines' service obligations and the actual level of service that customers are willing to purchase?

(A) Customers should be allowed to elect the level of service they desire. However, pipelines should not be required to hold supply for customers without financial renumeration. Obligations should be mutal between parties. NGSA advocates the use of a gas inventory charge (GICs) to resolve inequities that exist as a result of the service obligation and to resolve future take-or-pay problems. While NGSA does not advocate a particular type of GIC, we feel that their eventual adoption would rationalize contracts between pipelines and their customers. Indeed, the mechanics of a particular GIC are far less important than the Commission's continuing efforts to resolve these problems with the broader policy objective of maximizing completion in the production, transmission, and sale of natural gas. It also should be noted that many service contracts have recently expired or are due to expire in the near future. We anticipate that these contract expirations will give pipelines and their customers an opportunity to realize their respective service obligations and purchase commitments. Consequently NGSA believes that such negotiations may make significant inroads to resolving the current discrepancies.

Thank you again for the opportunity to present NGSA's views on gas supply and deliverability. If we can be of any further assistance, please feel free to contact us.

Sincerely,

Nicholas J. Bush

NJB/uev

ENRON CORP

Kenneth L. Lay
Chairman, President and
Chief Executive Officer

P. O. Box 1188
Houston, Texas 77251-1188
(713) 853-6773

October 23, 1989

Senator Jeff Bingaman, Chairman
Subcommittee on Mineral Resources
Development and Production
United States Senate Committee on Energy
and Natural Resources
Washington, D.C. 20510-6150

Dear Senator Bingaman:

Enclosed please find my answers to the additional questions posed by your subcommittee in connection with my recent testimony.

Sincerely,

Enclosure

QUESTIONS AND ANSWERS

Q.1. It is generally agreed that spot market sales of natural gas account for approximately two-thirds of all gas sales in the United States and that approximately one-half of spot market sales are under 30-day contracts. Have natural gas purchasers come to rely too much on the spot market in lieu of purchases under long-term contracts?

A.1. Yes, Enron believes that the spot market has "overachieved". Today, spot gas represents perhaps 70 to 75 percent of all sales. In the future, we would expect spot sales to represent perhaps 25 percent of all sales. Thus, while there will be a large and healthy spot market in the future, it will be substantially smaller than it is today.

Q.2. What are the likely consequences should this level of reliance on the spot market continue for much longer?

A.2. An excessive reliance on the spot market sends inappropriate price signals to producers. As a result, producers will drill for less gas than they would if customers were valuing security of supply. The typical spot gas contract allows for interruption by either buyer or seller and usually flows under an interruptible transportation contract. If a local distribution company's load is comprised of 75 percent high priority residential/commercial customers, one would not expect that company to buy 75 percent of its gas on the spot market because spot gas can be interrupted. For much of the 1980's, gas supply was in surplus and interruptions in spot gas service could be easily replaced by another seller. In a supply constrained environment, it will be more difficult to replace interrupted spot supplies. Thus, an LDC which did not plan for the possibility of interruption of spot gas on a cold winter's day might have to curtail firm customers. This is the "institutional failure" John Sawhill alluded to in his testimony. Customers with firm gas requirements such as local distribution companies (LDC's) will need to develop supply portfolios which match their supply contracts with their own load characteristics. If these portfolios appropriately balance supply security with price, supply interruptions to firm customers will be rare indeed.

Q.3. What will it take to get natural gas purchasers to return to longer term contracts?

A.3. Today, LDC's have a cost free form of supply insurance because natural gas pipelines have a service obligation to sell gas to a customer whether or not the customer takes gas from the pipelines. Pipelines must be compensated for this service with something like a gas inventory charge or they should be relieved of the service obligation. Alternatively, the pipeline sales service could be deregulated.

State Public Utility Commissions (PUC's) could also facilitate the process by letting LDC's know that the LDC's gas purchasing practices will be judged prudent if they balance longer term supply considerations with least cost. Some PUC's have inadvertently encouraged an excessive reliance on spot gas by comparing the LDC's long term gas purchases to prices available on the spot market.

Enron believes that the solution to this problem lies in regulatory reforms by the Federal Energy Regulatory Commission (FERC) and by state PUC's, rather than in Congressional Legislative action.

Q.4. In your testimony to the Subcommittee, you differ with respect to the elasticity of supply and demand for natural gas and the consequences that this might have. Do you differ with respect to the natural gas policies that the Department of Energy and the Federal Energy Regulatory Commission should pursue in the 1990's? Please specify the policy initiatives that you believe should be undertaken in this area.

A.4. Enron's study shows that natural gas is there (and can be drilled) if producers see the right price signals. While the gas industry has made tremendous progress since The Natural Gas Policy Act was passed in 1978, more reforms are needed before gas can play its full role.

1. The President's Clean Air Act proposal, with its "freedom of choice" environmental policy, goes a long way towards providing market incentives for cleaner fuels (like natural gas). Under current policy, fuels compete on their energy content, not on their cleanliness. If the nation is to solve its pollution problems, environmental consequences should become a major consideration in individual and corporate fuel selection.

2. Reform of the Public Utility Holding Company Act is needed to allow gas-fired powerplants built by independent power producers (IPP's) to provide competitively priced electricity to the nation's consumers. Gas-fired facilities are faster to build, more efficient, and more environmentally acceptable than competing technolgies.

3. In the gas market itself, the regulators and industry participants should support new forms of long term contracting. An excessive reliance on the spot market has contributed to depressed prices and depressed drilling activity. Specifically, we must reform the merchant function of natural gas pipelines to:

   - restore mutuality of contract;
   - relieve pipelines of service obligations where there is no mutuality; or,
   - deregulate the merchant function.

Local Distribution Companies (LDC's) can act on their own today and in the near term to assure supply during the forthcoming tight period by signing long term supply contracts. Private parties can structure deals to give producers incentives to drill today for the longer term supply needs of the customers. But, State Public Utility Commissions must encourage a balance between supply security and "least cost" purchasing policies by LDC's. Too often in a surplus market, least cost purchasing policies have led to an excessive reliance on spot gas to serve the LDC's firm residential market. As the gas market becomes supply constrained, security of supply should become an increasingly important factor in LDC's gas purchase decisions.

4. The Congress should reconsider drilling incentives. While broad based drilling incentives are less distortive, targeted incentives such as a tax credit for coal seam and tight sands gas are less costly to the Treasury. The supply response shown in the low drilling cost case suggests that this type of initiative would produce a significant supply response.

There are three broad policy implications of our supply evaluation:

1. The legislative and regulatory reforms of the last decade (wellhead decontrol, open access), make it very unlikely that the nation will experience gas shortages like we did in the 1970's.

2. Natural gas can and should play an important role in solving the nation's environmental and energy security problems. However, current policy does not recognize the major constructive contribution which natural gas can and must make.

3. Further reforms are needed to improve the functioning of the natural gas market and to complete the transition to a more competitive market. These reforms are important not only to the gas industry but are important to the nation if we are to solve our pressing environmental and energy security problems.

Q.5. You testified that Enron believes there is an extremely large North American gas resource base that will be obtained at very reasonable prices, and be more than sufficient to support a growing market. Your detailed study considers the potential for significant new demand from gas-fired electric generation plants built by independent power producers, and significant environmentally driven demand increases from natural gas vehicles, gas co-firing by electric utilities, and industrial users.

The Enron study concludes that the "hard landing scenario", with its sharply higher prices and tight supplies, as predicted by John Sawhill and others, is flat wrong. Yet, as I made part of the record in the June 1989 debate on gas wellhead decontrol, Enron gas supply officials testified at an April 1989 National Energy Board of Canada (NEB) export license hearing that your company "perceives a forecast of critical shortage of gas supplies on the

Enron system [by 1996]". Enron witnesses also said that the company has "a large appetite for gas"; and that the 1990's U.S. market could absorb Alaskan supplies, MacKenzie Delta Canadian supplies, and imported LNG due to "the expectation that domestic traditional supplies will decline in the post-1995 period". Enron's sworn testimony to the NEB also stated that:

> "Part of the circumstance of the increase in transportation volumes is attributable to the temporary surplus deliverability situation which exists within the U.S. market. The expectation that that spot market will probably be absorbed and no longer exist within the next three, four, five, you name it, number of years, has convinced Enron to recommit itself to the merchant function, as the most stable, secure long-term supplier to its customers. And together with the expectation that customers will no longer have access to spot market gas, they will look to again relying on the pipeline supplier. It is that type of thinking that goes into the expectation that Canadian gas will be required...we would no longer have a situation in which there is transportation gas per se, unless Mr. Esslinger was extremely successful in his non-jurisdictional sales activities."

(a) How do you reconcile the major differences in your prediction of extremely large, reasonably priced supplies with the recent testimony of Enron gas supply witnesses before the NEB predicting critical shortages by the mid-1990's?

(b) Your gas supply expert witnesses at the NEB hearing seem to be predicting the end of open access transportations for most consumers soon after the supply bubble bursts. Do you agree with them? Please explain in detail.

A.5(a) One of the major conclusions of Enron's study is that there is a substantial and growing role for competitively priced natural gas imports. In our assessment, imports from Canada and liquified natural gas sources (LNG) grow from 1.3 Tcf today to 2.6 Tcf by the year 2000. As explained the the White Paper which Enron submitted for the record, one could get to the same outlook by assuming a different mix of LNG and Canadian sources. As the "low drilling cost" case illustrates, if gas supplies are available at a lower cost, the gas market can grow from 19.2 to 20.9 Tcf in the year 2000. In essence, we conclude that the gas market is supply constrained in the 1990's. This means that if gas supplies from the MacKenzie Delta, LNG, or Alaska are competitively priced, there is an important role for these supplies in the U.S. market.

The "critical shortage of gas supplies on the Enron system" [by 1996] referred to by the Enron Gas Supply official is so described because currently contracted-for gas reserves on the Enron system are declining rapidly. Enron has identified a significant need to contract for new reserves and deliverability and this need creates "a large appetite for gas". In addition, Enron is seeking to grow its market share by selling gas on a non-jurisdictional basis outside its traditional service area. This desire for market expansion also creates a "large appetite" for new gas sources from which to contract. The range of volumes of gas from the MacKenzie Delta in which Enron expressed an interest was 200 to 300 MMcf/d (or 73 to 109 Bcf per year), which is less than 6% of the total Canadian imports we project in the year 2000.

Finally, Enron's study shows that domestic supplies from traditional areas will decline in the post-1995 period. Supplies from largely untapped domestic areas such as the Rockies and Mobile Bay are needed as well as unconventional gas to offset the decline in these traditional areas. Our study also found that there is a market for competitively priced Canadian, Alaskan and LNG sources as well as domestic supplies.

A.5(b) Enron predicted at the NEB that spot supplies would play a substantially diminished role in the U.S. gas market after the bubble bursts. As evidenced by Mr. Esslinger's comments at the hearing, we did not intend to imply that there would be no role for spot gas. Mr. Esslinger stated that, from the non-jurisdictional marketing affiliate's standpoint, "Like any other seller on Northern Natural, we sell gas to the existing customers on Northern on a non-jurisdictional basis...we are currently a shipper, and anticipate continuing to be a shipper-supplier on a non-jurisdictional basis." It is Enron's expectation that spot gas will supply perhaps 25% of future gas market needs, in contrast to the 70 to 75% it supplies today. With the "end" of the bubble, Enron anticipates a reduction in the size of the spot market, but not an end to open access transportation. Long term supplies could be provided either by the pipeline or by a non-jurisdictional marketing company or producer which used the pipeline solely for transportation service.

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AGA

George H. Lawrence

October 18, 1989

Honorable Jeff Bingaman
Chairman
Subcommittee on Mineral Resources
  Development and Production
Energy and Natural Resources Committee
United States Senate
Washington, D.C. 20510

Re: Oversight Hearing on Natural Gas
    Supply and Deliverability

Dear Chairman Bingaman:

The American Gas Association was extremely pleased to present the results of four separate natural gas supply studies during the Subcommittee's oversight hearings on Tuesday, September 26, 1989. We are also pleased to follow-up our testimony by responding to your two written questions on pipeline service obligations.

No group is more concerned about the security of natural gas supplies than the distribution and transmission company members of A.G.A., who have the obligation to supply gas to millions of Americans. Thus, our member companies carefully analyze supply issues for all time frames. Just to recap our findings:

- In regard to supplies this winter, we expect that the gas surplus or "bubble" will end during 1990. Although deliverability at the wellhead has declined since the mid-1980s (because of the drilling slump) a 50% increase in gas from storage over the usage in 1980 should mean that there will be adequate deliverability this winter.
- In regard to near-term supplies, as demand increases there are four sources of gas -- Canadian imports; infill wells; currently nonproducing reserves; and LNG -- that could increase supplies .7 to 1.4 Tcf per year with just 12 months lead time. With 36 months lead time, 1.3 Tcf to 2.1 Tcf of additional gas production could be available to gas consumers.

- As to longer term supplies, the nation has an increasingly gas prone resource base that can continue to supply 20 - 25 percent of the nation's total energy through 2010. Importantly, these supplies come to market at low, mid-, and high energy price scenarios. In all cases, available supply in the year 2010 should be at least 18.4 Tcf -- more than the 17.7 Tcf of actual consumption last year.

All segments of the gas industry realize that oil and gas producers have been through a serious restructuring and downturn. But our latest study indicates that producers are very bullish on the U.S. natural gas resource base and that they will increasingly focus their domestic drilling efforts on natural gas. For example, we have seen gas well completions increase 7.5 percent in the first seven months of this year, while oil well completions were down about 39%. Rig counts increased also -- to 955 rigs in September from a low of about 750 earlier this year. We estimate that the rig count will reach about 1100 by year's end. The shift in drilling emphasis from oil to gas is a big reason for the excellent 1988 gas reserve additions. According to the Energy Information Administration, reserve additions were a surprising 130% of production, despite some very low rig activity.

To keep these production efforts going, and to stimulate drilling further, the industry needs certain regulatory and legislative changes.

Needed regulatory changes are highlighted by the follow-up questions that you sent to us. You note, quite correctly, that "during the past several years, interstate pipelines have released substantial gas reserves that have been dedicated to their supply. At the same time, these pipelines remain under a service obligation to sell gas to their customers on demand." Our study, Natural Gas for the Winter Heating Season, confirms your hypothesis (the study is attached for your convenience and incorporated in the hearing record as part of our testimony). Chapter 3 finds that, in order to ameliorate take-or-pay liabilities, pipelines have reduced their committed gas reserves by 58.6 percent. In terms of volume, from 1985 to 1990, pipelines released more than 45 Tcf. In addition, pipelines have not replaced normally declining production by signing long-term contracts for new reserves. Thus, your questions on pipeline service obligations highlight a crucial issue for our industry.

Your first question is "what would be the outcome if during a cold snap, customers called on pipelines to deliver gas at levels commensurate with the pipelines' service obligations?" We found that pipelines are generally confident that they can provide adequate supplies this winter, although the source of those supplies will be quite different compared to the past. Today, pipelines are more reliant on storage and spot gas than in the past. Storage capability, in particular, has increased significantly -- up 50 percent from the actual usage in 1980. Consequently, over 90 percent of the companies surveyed by A.G.A. were confident that supplies would be adequate on their systems, even if we experienced extremely cold weather this winter (See: pages 8 and 9 of the attachment).

Your second question is "what should be done to address the discrepancy between pipelines' service obligation and the actual level of service that customers are willing to purchase?" Simply stated -- the answer is to implement workable gas inventory charges. Such charges allow both the pipeline and its customers to bring the pipeline's service obligation in-line with the amount of gas that the customers actually intend to purchase. Indeed, this adjustment process may be the most important benefit of a gas inventory charge on some pipeline systems.

As you know, the Federal Energy Regulatory Commission's process for approving GICs has been extremely slow up to now. Your September 15 letter to Chairman Hesse, however, was a positive step and one we strongly applaud. Subsequently, of course, the Commission approved settlements by Transcontinental Gas Pipe Line and Columbia Gas Transmission, and their respective customers and producer suppliers. Therefore, we are hopeful that other settlement offers, which have broad customer and supplier support, will be approved. We look forward to working with you to ensure that, "permanent and interim GICs should not be consigned to a regulatory limbo."

Needed legislative changes were highlighted by our testimony during the oversight hearings. To stimulate drilling further, the industry needs tax credits, especially extensions of the tax credits for hard to produce gas resources such as coal seams, Devonian shale, tight formations, and geopressured brines. In one of these categories alone, coal seams, the gas industry added 1 Tcf of reserves last year.

We also strongly support increased offshore leasing, and recently joined with the Natural Gas Supply Association and INGAA in a letter on Outer Continental Shelf (OCS) leasing to the President's OCS Task Force and to Secretary of the Interior Manuel Lujan. If the nation is to reap the environmental and economic benefits of increased natural gas use, the industry must explore offshore areas. Simply wishing that natural gas resources might be found elsewhere is neither practicable nor realistic -- especially given the excellent offshore safety record that the natural gas industry enjoys.

The outlook for natural gas is strong. Our transportation system is efficient, extensive and flexible. Storage capability is at its peak -- over 50% larger than was used in the early 1980s. Our companies can handle increases in gas demand in existing and exciting new markets, such as high efficiency electric generation, gas cooling and natural gas vehicles. There is growing confidence among customers and public officials that natural gas is a secure and environmentally benign fuel. That confidence is justified.

Sincerely,

Bud Lawrence

George H. Lawrence

cc: Members, Subcommittee on Mineral Resources Development
    and Production

Attachment

AGA American Gas Association

Natural Gas for the Winter Heating Season

A Report of the A.G.A. Gas Supply Committee
September 1989

Natural Gas for the Winter Heating Season

A Report of the A.G.A. Gas Supply Committee

September 1989

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Executive Summary

The analysis described in this report, as well as extensive survey data generated from producers, pipelines and distributors, concludes that on a national average basis there should be adequate gas deliverability this winter. Gas supplies in the winter 1989/90 will reach the market through different suppliers than in recent history. Storage and spot gas will supply a larger percentage of distributor requirements. In contrast, pipeline system gas will be 41 percent of total peak month requirements in January 1990 compared to approximately 76 percent in January 1980. However, the ability of spot gas to satisfy seasonal requirements remains essentially untested. Evidence from the winters of 1987/88 and 1988/89 indicate the potential for spot price volatility. In addition, growth in gas demand in certain regions coupled with the above shift in gas supply mix may result in short-term regional supply discontinuities.

On a national average basis, January 1990 gas production capability is expected to be 10 percent lower than January 1980 *actual* production. On the other hand, gas storage send-out capability in January 1990 will be 51 percent greater than actual 1980 storage withdrawals reported by the Energy Information Administration.

- On a national basis, no imbalance between supply and demand is expected. The maximum monthly consumption of gas ever recorded in the U.S. was 2,426 Bcf in January 1979. A peak supply capability for the winter of 1989/90 is projected to be 2,444 Bcf. This supply forecast is based on:
  - maximum sustainable monthly production in 1990 (January) conservatively estimated at 1,600 Bcf — ten percent below the actual level of production in 1980
  - peak month storage withdrawal capability of 700 Bcf in 1990 up from 576 Bcf actual withdrawal in 1988; 697 Bcf is the highest demonstrated one month withdrawal capability
  - Canadian gas supplies (which provided almost 1.3 Tcf to the U.S. in 1988) are expected to be able to surpass the record monthly level of 138 Bcf established in January 1988 to 150 Bcf in January 1990.
- The A.G.A. survey for the first time included major gas producers. Producer respondents quantified the shift from committed gas sales in January 1980 of 98 percent of their sales to an expected 49 percent of sales in January 1990. These same producers described the purchasers of their gas in 1980 as 75 percent pipelines and 25 percent LDCs and end-users. These sales in January 1990 are expected to be 21 percent to pipelines, 25 percent directly to LDCs and 54 percent directly to end-users.
  - In response to a question concerning their gas supply expectations, if January 1990 were the coldest month in fifty years, the producers believed supplies would be adequate for all firm customers. Interruptible customers were likely to be interrupted during such a cold month. Spot market prices were expected to respond in a manner similar to the seasonal spot market variations observed in the past several years.
- As a result of a massive restructuring in the pipeline industry, system gas deliverability, (i.e., pipeline sales which includes production from dedicated reserves), has been reduced significantly throughout the 1980s.
  - To alleviate take-or-pay obligations and facilitate settlements, pipelines have released large quantities of committed gas reserves and deliverability. From 1985 to 1990 the companies in the A.G.A. survey are expected to release over 45 Tcf of reserves (over a quarter of the nation's lower-48 proved reserves).
  - Large quantities of pipeline reserves have been released causing a decrease in system gas deliverability. The pipelines which participated in the A.G.A. survey have lost about 40 percent of their system gas delivery capability since 1980.
  - The gas reserves and deliverability released by interstate pipelines now are the backbone of the spot market — it is the same gas but has radically different contractual and regulatory obligations.
- The mix of gas supplies available to interstate pipelines has changed between 1980 and 1990. The principal change in pipeline supply has been the purposeful reduction in dedicated gas supplies due to reduced demand from traditional customers.
  - Long-term field purchases

  for system supply accounted for 76 percent of pipeline throughput in 1980, but now contributes 41 percent.

  - Transportation represented only 5 percent of pipeline throughput in 1980. Transportation is expected to be 35 percent of throughput in January 1990.

  - Gas from storage will continue to be important, growing from 19 percent in 1980 to 24 percent, if needed, to satisfy the demand in a very cold winter.

- In January 1980, LDC requirements for system gas were 82 percent of the LDC total requirements for peak month gas. In contrast, LDC purchases of system gas are anticipated to be only 59 percent of their total send-out in 1990.

- LDCs have diversified their gas supply sources principally for cost reasons. Forecasts for the 1990 winter indicate that these trends will cause a major change in the mix of LDC supply from 1980 to 1990.

  - To offset the system gas supplies that were not purchased, LDC send-out of spot gas increased in this time period from 0 to 13 percent.

  - LDC send-out from other sources such as SNG grew from 18 percent in 1980 to 28 percent in January 1990.

- Spot gas, which represents the vast majority of LDC owned/committed gas, has substantially replaced system gas during both peak and off-peak periods. While this displacement is most severe during off-peak periods, it has also grown during periods of peak seasonal requirements.

  - The ability of spot gas to satisfy seasonal gas requirements is basically untested during a period of relative gas supply/demand balance.

  - The primary mechanisms for spot gas volumes to react to increased demand, such as cold weather, are through increases in spot prices and fuel switching. The price variations were clearly demonstrated during the last two winter heating seasons. Such temporary price run-ups and run-downs are likely again this winter. Several factors indicate that spot market prices are likely to become more volatile. The demand for spot gas is growing because spot gas is often less expensive than system gas. Additional factors which influence the variations in spot market sales are: (1) total gas demand is increasing (2) pipeline system sales are declining (3) supply, in terms of national production capability, is declining and (4) LDC and pipeline purchases of spot market gas will reinforce demand during cold weather.

- Spot market price volatility was evaluated for an extraordinarily cold month by the LDC survey respondents. They estimated that they would pay only 4.8 percent more for gas in January 1990 than they did in January 1988.

- As previously noted, the release of dedicated reserves by interstate piplines has resulted in the produced gas being purchased directly by LDCs (both spot gas and longer-term contracts). The change in ownership of this produced gas and how it reaches the marketplace could be an important factor during periods of peak demand.

- Additionally, these new mechanisms imply that redistribution of gas supplies during periods of peak demand will be accomplished by contract-price bidding instead of federally established curtailment priorities.

- On balance, adequate gas supply is anticipated during the coming winter. On the other hand, transportation bottlenecks and sharp swings in gas demand associated with cold weather are likely to lead to price volatility on the spot market. During short periods in localized areas, this could even result in physical delivery constraints on getting gas.

- This study tests the capability of the gas industry if severe cold weather occurs in an abnormal January with the preceding December and the following February reflecting typical temperature patterns. The analysis of the strain on the system which would occur if the extremely cold weather extended over a three month period is not reflected in this report.

Chapter 1

Introduction

The transportation segment of the gas utility industry has changed rapidly—both structurally and functionally. With many aspects of the transition still not resolved, an unusually cold winter heating season could stress the gas delivery system and create both price volatility and physical delivery problems in certain geographic regions. To date, the most severe test of the spot market and the new transportation arrangements occurred in January 1988.[1] Spot market prices surged rapidly in response to increased demand and a lack of flexibility relative to receipt and delivery points. With another winter heating season approaching, regulators and end-users wish to review recent trends and gain insights into the likely supply-demand-price interactions.

This report initially reviews historical supply-demand data from 1973 through 1989. This information provides the basis for the conclusion that no national supply-demand imbalance is likely to occur in any month of the coming winter heating season. However, as the pipeline system gas sales and committed reserves are considered, it is apparent that new mechanisms (e.g., brokering, producer-to-LDC direct sales, transportation, best efforts storage, best efforts sales to industrial customers) have become more important during the peaks of the winter heating seasons. Gas supplies have often been subject to price surges for all customers and supply disruptions to interruptible customers. Adjustments made by the gas utility industry to reduce end-user vulnerability to such events are outlined in this analysis.

Beyond the testing of the new mechanisms in the marketplace, the spot gas price variations become an issue of great importance to all — producers, pipelines, distributors and end-users. The report concludes that spot gas prices have become increasingly volatile, that spot prices now influence almost all gas prices, and that spot price volatility has followed seasonal demand patterns.[2]

The methodology to develop the aggregate statistics presented in this analysis that describe gas supply and send-out volumes, reserves and pricing data began with a survey of all A.G.A. member companies, pipeline and distribution alike. In addition, major producers were asked to contribute data on their gas sales and obligations. Each pipeline company was asked to supply data regarding system, storage and transportation gas for the months of January 1980, 1985, 1988, and 1990. Local distribution companies (LDCs) were asked to provide data on gas supply and send-out for the same time period. Actual data were reported for January 1980, 1985, 1988 and estimated data for 1990. Pricing information was also requested of all gas utilities. All companies were asked to base their January 1990 estimates on the assumption that this would be the coldest January in 50 years. Therefore, for January 1990 a near worst case scenario is presented: the supply, transportation and delivery systems are assumed to be under a maximum stress.

Survey replies include gas supply data from 28 pipeline companies and 73 LDCs. Pipeline company responses represent a broad geographic distribution as well as a broad range of company sizes. Likewise, LDCs replying are geographically diverse, include small and large distribution systems and include companies with customer bases anchored by residential, commercial and industrial sales and combinations of the three. In order to present data and conclusions on a national scale, inputs from survey responses are aggregated rather than presented individually. This technique also protects those companies that provided information considered proprietary or confidential.

Chapter 2

Gas Supplies and Demand

In assessing the adequacy of gas supplies for the 1989-1990 winter, this report examined both supply availability and gas demand projections. The supply estimates of this portion of the report are based on how much gas could be supplied from each source for which good statistical data are available—conventional production, imports, etc. This total volume, which could be available in January 1990, is compared to the record level of monthly consumption in the U.S., which is used as a demand constraint. These potential supplies exceed the highest monthly consumption ever recorded in the U.S. Only if demand in January 1990 exceeded the historic high, could one anticipate a national volumetric gas supply problem. Supply availability could also be affected by a sustained (several months) cold period that would reduce storage supplies. On the other hand, the ongoing restructuring of the gas industry could create other types of supply problems. It is important to realize that the

Table 1
Maximum Monthly Gas Supplies and Consumption - 1973 through January 1989
(in Bcf)

Year	Production[1]	Domestic Supplementary Gas[2]	Imports[3]	Storage Withdrawal[4]	Consumption[5]	Data Sources
1973	1912 [6]	--	79	--	2348	*Monthly Energy Review*, Dec. 75
1974	1849 [6]	--	86	--	2230	*Monthly Energy Review*, Dec. 76
1975	1705 [6]	--	84	371	2248	*Monthly Energy Review*, Dec. 76
1976	1677		86	526	2291	*Monthly Energy Review*, Jan. 79
1977	1665		101	670	2407	*Monthly Energy Review*, Jan. 79
1978	1672		87	668	2385	*Monthly Energy Review*, Jan. 79
1979	1751		114	673	2426	*Monthly Energy Review*, Dec. 83
1980	1777	18	118	465	2263	*Monthly Energy Review*, Mar. 84
1981	1684	20	93	571	2279	*Monthly Energy Review*, Aug. 85
1982	1657	19	110	697	2400	*Monthly Energy Review*, Aug. 85
1983	1530	17	112	634	2191	*Monthly Energy Review*, Mar. 87
1984	1629	17	97	563	2219	*Natural Gas Monthly*, Feb. 88
1985	1559	13	106	661	2148	*Natural Gas Monthly*, Feb. 88
1986	1536	12	99	421	2106	*Natural Gas Monthly*, Feb. 88
1987	1533	11	121	521	2051	*Monthly Energy Review*, Apr. 89
1988	1535	17	138	576	2168	*Monthly Energy Review*, Apr. 89
1989	1503	16	119	397	2008	*Monthly Energy Review*, Apr. 89

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[1] Dry gas production.

[2] Includes SNG from liquid hydrocarbons, propane-air, LNG storage, landfill gas, coke oven gas.

[3] Canadian gas and LNG imports.

[4] Underground storage withdrawals.

[5] As reported by EIA.

[6] Reported as marketed production. These statistics have been adjusted to represent dry gas production using a factor of .959 which is based on 1977-78 data for March and December.

[7] January - June only.

Table 2
Estimated National Maximum Supply and Consumption Levels For 1989-1990 Winter

Source	Volume in Bcf	Remarks
Conventional Production	1,600	1,629 Bcf was demonstrated in January 1984; 1,534 Bcf was demonstrated in January 1988
Storage withdrawal	700	697 Bcf withdrawal occurred in January 1982
Domestic Supplemental Sources - propane air, LNG storage, landfill gas,	17	17 Bcf was demonstrated in January 1988
LNG Imports	2	2.8 Bcf is a maximum shipload (129,500 cubic meters)
Canadian Gas Imports	150	138 Bcf was demonstrated in January 1988; 150 Bcf is based on pipeline capacity
Exports, Storage Injections	(25)	Based on minimum storage injections and exports historically
Total Supply Capability	2,444 Bcf	
Maximum Consumption January 1979	2,426 Bcf	

concern is not the level of gas available on a national basis — rather it focuses on the ability of that gas to get to market.

Table 1 tabulates the highest monthly gas supplies and consumption levels for each year from 1973 through May of 1989. The highest supply reported by the Energy Information Administration (EIA) for any month in each year is listed. The conventional production maximum could have occurred in one month and the maximum for withdrawal from storage could have occurred in another for a given year. In the table only the supply for the highest month in the year is listed. Inasmuch as the supplies are largely independent, the maximization of one source does not argue against the other sources being maximized.

Conventional production is by far the largest supply source with the monthly maximum values ranging from the 1,530 Bcf to 1,503 Bcf lows in 1983 and January 1989, respectively (undoubtedly demand restrained) to the peak of 1,912 Bcf in 1973. Maximum monthly underground storage withdrawals vary greatly also—a low of 371 Bcf in 1975 to the high of 697 Bcf in January 1982.

Domestic supplemental gas sources contribute locally important volumes of gas, but nationally the total gas supply is only about 11-20 Bcf per month. The peak level in recent years was the 17 Bcf which was produced in January 1988. This category includes propane-air, LNG storage, landfill gas, SNG from liquid hydrocarbons, coke oven gas, etc.

Imports include Canadian, Mexican and LNG shipments. The data tabulated in Table 1 are primarily Canadian gas; however, Mexican gas imports are included for the years 1977 and 1980 through 1984; LNG imports are incorporated in the years 1973 to 1986 and 1988.

Storage withdrawals are based on EIA-191 survey results. The volumes reported do not reflect the injections of gas into storage even though they may have occurred in the same month. Typically gas is being injected into storage every month. Withdrawals are usually about ten times greater than injections during the winter heating season. For the purposes being considered here, a maximum withdrawal capability is used in Table 1. Table 2 includes an allowance for injection of gas into storage.

Consumption statistics are also EIA data and include all normal consumption categories as well as the gas allocation made by EIA as "unaccounted for".

Table 2 combines the sources of supply at the maximum level which might be available in January 1990 and compares that total to the maximum recorded level of consumption (which occurred in January 1979). This maximum consumption level was 2,426 Bcf. Aggregate supplies available for January 1990 were projected to be 2,444 Bcf. Therefore, on a national basis there appears to be an adequate supply of natural gas to satisfy requirements even if consumption equalled the record level set in 1979. This evaluation does not consider the regional issues. For example, some regions of the country face "receipt point" problems relative to gathering and transportation. Other regions face delivery point problems. These issues are considered in other chapters. Also omitted in Table 2 is the potential impact on these sources of supply from Acts of God such as severely cold weather causing producing wells to freeze up or hurricanes in the Gulf of Mexico, either of which could limit regional production to only a fraction of its normal level.

Demonstrated conventional production (dry) was in excess of 1,600 Bcf in four of the years from 1980 to 1988. In 1980 the production level was 1,777 Bcf. The estimate of current capability uses the data in Tables 2 and 3. Table 3 presents a tabulation of the daily production rates for the month of maximum production for six major gas producing states and the total U.S. The final five columns of the table show the ratios of the production in that state for 1985, 1986, 1987, 1988 and the first two months of 1989 as compared to 1980. The general conclusion is that while production levels are typically lower in the later years, the capacity to produce gas nationally has been demonstrated at 88-90 percent of the 1980 level. At worst, the data indicate a decline of ten to twelve percent. At best, there has been no loss in production capability at all. The worst case would be valid if actual February 1989 production (52.2 Bcf per day) was the maximum capability; the best case would be if February 1989 production could have been higher, but the full capability was not achieved because of reduced production associated with limited demand.

The 1,600 Bcf monthly production capability is based on a nominal ten percent loss in production from 1980 to 1988 as indicated in Table 3. If this reduction is applied to the 1980 peak month production in Table 1, a level of 1,600 Bcf is suggested. Unusually strong reserve additions for the lower-48 states in 1988, as reported by EIA, suggest a reserve base capable of this level of production. Also, a greater percentage of the total drilling activity is now apparently gas oriented. This may indicate a stronger gas oriented response when drilling activity returns to the higher levels of the early 1980s.

In 1984, many Texas wells were shut in by freezing weather which severely limited production at that time. Subsequently, there has been extensive speculation that the Texas gas production capability could be significantly lower than it was in 1980.[3] Table 3 statistics on Texas production indicate that in 1988 the Texas production level was demonstrated at 90.9 percent of the maximum production level achieved in any year since 1980.

On balance, the 1,600 Bcf level seems to be a conservative assessment of what the maximum dry conventional production for the U.S. might be for the peak month during the 1989-90 winter heating season.

Storage withdrawal capability is listed in Table 2 as 700 Bcf. This level is 3 Bcf higher than the maximum month withdrawal in January 1982. Many factors influence this estimate. (See Appendix I for historical statistics on underground gas storage.) The single most important factor is the quantity of gas in storage at the start of the month. For example, in January 1982 the total gas in storage at the beginning of the month was 6,569 Bcf. At year-end 1988, 6,672 Bcf was in storage. How much gas would be in storage at year-end 1989 is unknown. However, as will be discussed in Chapter 3, there is an expectation that storage will be a more important part of pipeline supplies this winter so that one could assume that storage will be relatively full at the start of the winter heating season.

Domestic supplemental sources describe a variety of types of gas—SNG from liquid hydrocarbons, propane-air, LNG storage, landfill gas and coke oven gas. It may be that the demonstrated 17 Bcf for January 1988 is lower than might be obtained from these sources. For example, seasonally operating SNG plants have a design capability to produce 19.5 Bcf in a 31-day month.[4] However, in the 1987 - 88 winter heating season these plants produced only 4.1 Bcf. Economics are the primary cause of this low production level. If competitively priced naphtha, propane, butane, etc. were available during a period of peak demand, higher production levels would be possible. Despite this potential, the January 1988 demonstrated level of 17 Bcf is listed in Table 2.

LNG imports could easily provide the 2 Bcf listed in Table 2 into the Distrigas terminal at Everett, Massachusetts. If the Lake Charles facility is operational (an authorization for operation has been requested), LNG imports could be substantially higher.

Canadian gas imports were 138 Bcf in January 1988. Although many of the import lines were operating at full capacity during January, not all of the importing systems did receive the full import capability. Maximizing the flow of gas at each import point could raise the level for a month to 150 Bcf.

Deductions of gas supply for storage injections and exports are shown in Table 2. This level of 25 Bcf is consistent with historic low levels of injections and exports. Geographically, the gas exports are primarily from southern Alaska to Japan, and the storage injections usually occur in areas where gas demand is not extreme. Therefore, these volumes would not seriously affect the gas supply in areas of peak demand. However, Table 2 includes them for completeness.

Table 3
Demonstrated Natural Gas Production In Peak Months

	Daily Production Demonstrated in Peak Month*										Ratios				
State	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989[1]	1985/1980	1986/1980	1987/1980	1988/1980	1989/1980
Kansas	3,270	2,188	2,191	2,057	1,967	2,194	1,903	1,929	1,948	1,607	.671	.582	.590	.596	.491
Louisiana	20,446	19,686	18,709	15,928	18,535	16,537	15,814	15,112	15,088	15,117	.809	.773	.739	.738	.739
New Mexico	3,339	3,339	3,307	2,972	3,061	3,148	2,420	2,804	2,727	2,551	.943	.725	.840	.817	.764
Oklahoma	6,444	6,252	6,611	5,608	6,182	6,246	5,846	5,932	5,698	5,964	.969	.907	.921	.884	.926
Texas	20,143	19,511	19,013	17,483	18,482	18,284	18,036	18,382	18,309	17,573	.908	.895	.913	.909	.872
Wyoming	1,308	1,345	1,378	1,509	1,588	1,356	1,502	1,690	1,981	2,247	1.037	1.148	1.292	1.515	1.718
U.S.	59,061	55,974	55,749	51,763	55,881	53,054	52,077	51,862	51,909	52,201	.898	.882	.878	.879	.884

* In MMCF
1. January-February only.

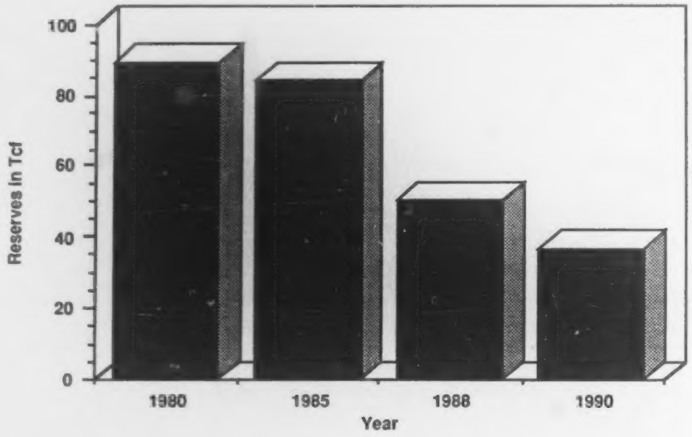
Source: EIA, *Natural Gas Monthly*, April 1989

Chapter 3
Pipeline Company Trends

Most major pipeline systems provided A.G.A. with statistical data and projections of supplies and requirements covering the period from 1980 through 1990. These pipelines report that there has been a major reduction since 1980 in the demand for system gas. The term "system gas" is used in this report to describe gas sold by the pipeline. It includes the gas acquired by the pipeline from dedicated production, purchases from other pipelines and storage. As a result of this decreased demand for system gas, the pipelines have released large amounts of committed gas and/or sold their company-owned gas reserves. Although a portion of this gas can be "recalled" by the pipelines, no quantification of the volume which could be recalled is available. Figure 1 shows the decline since 1980 when 88.6 Tcf was under pipeline control to 1990 when only 36.7 Tcf will be owned or committed to the pipelines. Although the 58.6 percent drop in reserves was necessary to stem the growth of take-or-pay obligations, the loss in reserves sharply reduced the pipelines' capability to deliver system gas. However, the pipelines are still transporting the traditional quantities of gas. Today, the combination of transportation gas and system gas satisfies the pipeline customers' demand for gas. The question to be answered is, if a severely cold winter occurred, would the transportation gas plus system gas be adequate to satisfy demand? There is very little doubt that system gas supply capabilities have been reduced to the point that system gas would, by itself, be unable to satisfy the same share of a peak month load as it did in earlier years. Volumetrically, transportation gas plus system gas is adequate to satisfy demand as shown in Table 2. The flexibility of this system to satisfy seasonal requirements remains essentially untested.

Pipelines have experienced a sharp reduction in the purchases of system gas (see Figures 1 and 2). For the pipelines that responded to the A.G.A. survey, the percentage shares of total deliveries are shown in Table 4. The decline in system gas sales was from the January 1980 level of 76 percent of deliveries to the January 1990 level of 41 percent—a loss of 35 percent. Not surprisingly, these same pipelines reported that they have reduced their committed gas supplies by 58.6 percent. From 1985 to 1990, the quantities of gas being

Figure 1
Reserves Owned By/Committed to Pipelines
1980-1990
(in Tcf)



released exceeded 45 Tcf. In addition to the released gas, pipelines' committed reserves have been declining as a result of production. Since these reserves have not been replaced, the decline in committed reserves is exacerbated.

The release of gas committed to the pipelines has been an important element in both take-or-pay settlements and reduction in accrual of new take-or-pay obligations.

Offsetting this decline in system gas were the major increases in transported gas shown in Figure 2. Survey respondents reported increases in transported gas from 69 Bcf in January 1980 to 554 Bcf estimated for January 1990.

At the reduced level of commitments system gas delivery capabilities have been reported in aggregate to be about 40 percent lower than they were in January 1980. (Note: deliverability has tended to fall less rapidly than reserves due to increased capability to produce committed reserves faster.) To provide a maximum delivery of system gas in January 1990, the mix of pipeline supplies would be quite different from the mix in January 1980. This transition is reflected by the percentage shares of pipeline supplies as shown in Table 4. In Table 4, January 1980, 1985 and January 1988 data characterize the changes with actual statistics on what occurred in those months. The January 1990 estimates, in contrast, are the estimated levels of system gas which could be provided with strong demand. Clearly, the role of system gas is less now, due to released gas, than it was in 1980. Furthermore, system gas now includes some spot gas purchases by pipelines. Storage has become much more important, rising from 19 to 24 percent. In addition to increased percentage shares, the actual volumes of gas expected from storage also are greater, up to 50 percent more in 1990 as compared to 1980. Monthly requirements for 1987 for a representative pipeline illustrate the highly seasonal demand for system gas in Figure 3.

These data suggest that the pipelines, faced with sharply reduced demand for system gas, reduced committed gas supplies and, as a consequence, they will be more dependent on storage during periods of peak demand for system gas. If cold weather caused an extensive draw-down in regional storage, this would further restrict the pipelines' ability to deliver high levels of system gas.

Overall, the pipelines in the survey were extremely optimistic about the gas supply situation for the 1989-1990 winter heating season, even if extraordinarily cold weather were experienced in their service area. Over 90 percent of the companies expressed confidence in the adequacy of supplies

Table 4
Percentage Share of Pipeline Supplies (1980-1989)
(for the Months of January)

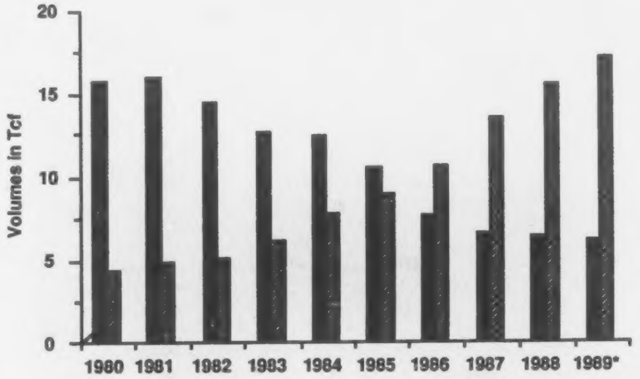
Year	System Gas	Storage	Transportation	System Supply
1980[1]	76	19	5	100
1985[1]	56	22	22	100
1988[1]	42	20	38	100
1990[2]	41	24	35	100

---

1. Actual deliveries.
2. Estimate is the maximum capability to deliver system gas in January 1990

on their systems. Some companies expected curtailments to affect non-dual fuel users if January were the coldest January in the past 50 years. In contrast, 82 percent felt that even under these extremely severe weather conditions, if any curtailments occurred, it would affect only dual-fuel customers. A distinct minority foresaw significant curtailments in a severe weather environment as likely.

Figure 2
Gas Sales and Gas Transported [1]



Sources:
Gas Sales: *A.G.A. Gas Facts*, 1987
Gas Transported: *EIA Natural Gas Monthly*
[1] Gas transported by Major Interstate Pipelines

Chapter 4

Distribution Company Trends

Over 70 local distribution companies (LDCs) responded to the A.G.A. survey. Well over ninety percent of these companies anticipated little or no difficulty in terms of adequacy of gas supplies for the coming winter heating season. Several companies were very cautious on this issue. If the winter were extremely cold, these companies anticipated significant spot market price increases and the potential for curtailment of low-priority non-dual fuel customers. Two companies that responded to the survey were quite pessimistic about their ability to handle the coldest month in 50 years without serious curtailments of non-dual fuel customers. These companies also envisioned sharp spot market price increases which would, perhaps, cause the end-users to initiate the needed curtailments.

One steadily changing aspect of the LDC gas supply programs is the steady shift away from dependence on pipeline system gas and toward independently contracted spot and longer-term gas supplies. Table 5 illustrates the change. In January 1980, survey respondents received 734 Bcf (82 percent of their total supplies) in the form of pipeline supplies of system gas. Their estimate for January 1990 is that only 586 Bcf (59 percent) would come as system gas. This January 1990 estimate is maximized because of the assumption that January 1990 would be the coldest month in 50 years and for that reason maximum supplies would be obtained from all suppliers. This decline in the use of system gas is consistent with the data reported by the pipelines regarding the rapid erosion of their system gas sales.

To counter the loss of system gas supplies, producer gas purchases (spot and longer-term) have increased from less than one Bcf in January 1980 to over 127 Bcf (13 percent of total supplies) estimated for January 1990. A lesser increase was reported for other sources of gas supply (LDC storage, including non-pipeline system supply, contract storage and owned storage, SNG, propane-air, etc.). From January 1980 (162 Bcf, 18 percent of supplies) the "other category" is expected to increase to 285 Bcf, 28 percent of supplies in January 1990.

As described earlier, the survey assumptions were formulated to create a severe stress on the gas industry in January 1990. This month was assumed to be the coldest month in the past fifty years (in each company's service area). Of special interest is, how these extreme weather conditions would alter the LDC load? Certainly there would be increased percentages of residential consumption, but how would the industrial customers fare?

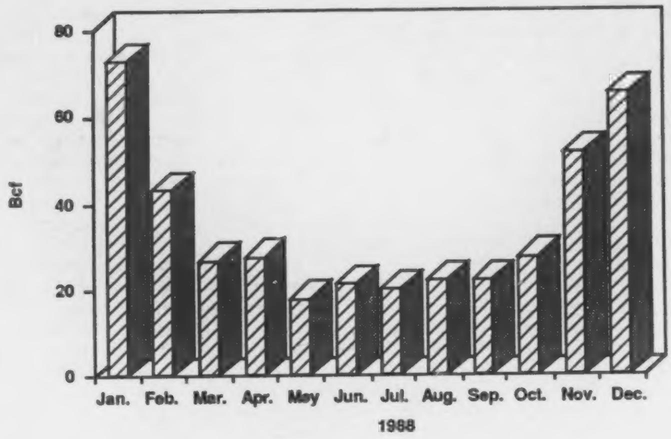
Table 6 summarizes these results. Residential and small commercial customers used 462 Bcf (60 percent of total send-out) in January 1980 rising to 518 Bcf (71 percent of total send-out) in the very cold January 1988. This group is expected to consume 571 Bcf if January 1990 has severe weather. In other words, the cold weather of January 1988 caused a 56 Bcf increase in consumption over January 1980 (518 Bcf less 462 Bcf). With the weather assumptions of the survey, demand by residential and small commercial would rise an additional 53 Bcf (571 Bcf less 518 Bcf) in January 1990. Interestingly from a percentage of total send-out viewpoint in January 1988, 71 percent was consumed by residential/small commercial customers. Under severe weather conditions assumed for January 1990 there would be no increase in the portion of total send-out going to the highest priority customers.

Table 6 also illustrates the percentages of total send-out which survey respondents attributed to the large firm/commercial industrial loads and the interruptible loads. Clearly the firm customers share of the total send-out was relatively constant at 17-22 percent. In contrast, interruptible customers would receive only nine percent of total send-out for the cold month assumed for January 1990 as compared to the more customary levels of 15-18 percent in January 1980 and 1985 or the 12 percent received in the cold (but not severely cold) January 1988.

The customers which constitute the interruptible load for the responding distribution companies have been changing their capabilities since 1980 (see Table 7). The dual-fuel customers load for 34 percent of the respondents has been increasing since 1980. This load remained about the same for 32 percent of the respondents and 34 percent reported that the dual-fuel load had decreased on their systems since 1980. There has been some speculation[5] that the dual-fuel customers would not be able to switch to alternate fuels because they had not properly maintained the equipment necessary to use the non-gas fuel. This question has been investigated in a recent A.G.A. survey. The results were that dual-fuel customers are generally capable of using alternate fuels, if needed. This survey reinforced the earlier data; 70 percent reported a high state of readiness, 29 percent were only partially ready and only one percent expressed doubts that these dual fuel customers had the capability to switch to alternate fuels.

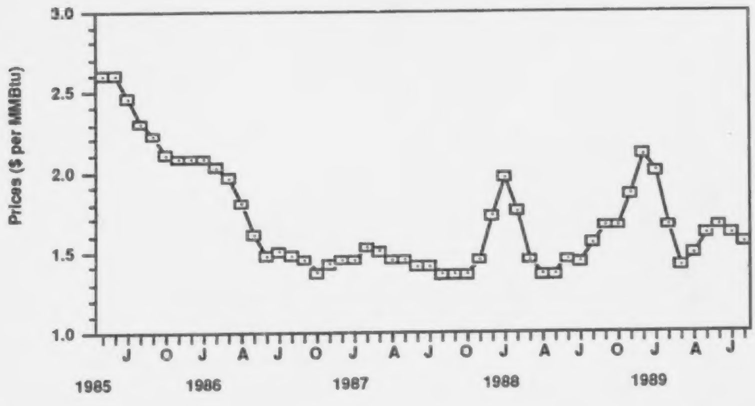
With the increased LDC dependence on spot gas there has been concern regarding the likely surge in gas prices during a severely

Figure 3
Estimated Monthly Pipeline Requirement - 1988



Source: *Natural Gas - Next Winter,* November 1988.

Figure 4
Spot Market Prices



NOTE: The values plotted are the mediam spot prices from data reported by the Natural Gas Clearinghouse.

Table 5
Percentages of LDC Gas Supplies from Different Sources 1980-1990 (for the Months of January)

Year	Pipeline System Gas	Spot Gas Purchases	Other[1]	Total
1980	82	0	18	100
1985	78	2	20	100
1988	66	11	23	100
1990	59	13	28	100

---

[1] Other category includes LDC storage, non-pipeline system supply, contract and owned storage, SNG and propane-air.

cold month. The prices paid by LDC for January 1980, 1985, and 1990 (estimated) are shown in Table 8. The total spot market prices as reported by the Natural Gas Clearinghouse are displayed in Figure 4. The important result of the LDC data is that only a 4.8 percent rise over January 1988 is estimated for January 1990. The severity of the assumptions about the January 1990 temperature would cause major stresses on supply acquisitions in the spot market. Yet, only a 4.8 percent increase in the gas acquisition price is expected by the LDCs.

Table 6
Percent Share of Distribution Company Send-Out (for the Month of January)

Year	Residential and Small Commercial	Firm, Large Commercial and Industrial	Interruptible	Total Send-Out
1980[1]	60	22	18	100
1985[1]	65	20	15	100
1988[1]	71	17	12	100
1990[2]	71	20	9	100

---

[1] January statistics.
[2] Send-out capability estimated for January 1990.

Table 7
Dual Fuel Customers as Reported by LDC

Growth of Dual-Fuel Load Since 1980	Percent of Respondents
Larger Demand in 1989	34
Demand in 1989 About the Same	32
Less Demand in 1989	34

Dual-Fuel Customers Ability to Use Alternate Fuel	Percent of Respondents
Prepared to Switch	70
Partially Prepared to Switch	29
Many are Unable to Switch	1

Table 8
Average January Price Paid for Natural Gas by LDCs
(in $ per MMBtu)

Year	Price	Percent Change Since 1980 (per year)
1980	$2.38	--
1985	$3.90	+10.4
1988	$2.93	+ 2.6
1990	$3.07	+ 2.6

Note: The percentage changes tabulated are annual changes; the 1990 and 1988 percentages reflect the annual growth since 1980 and are nearly equal.

Chapter 5
Major Natural Gas Producers

Natural gas supply during an extremely cold month depends on producers' ability to maintain or increase natural gas production. Most of the increased gas supply needed for the hypothesized January 1990 would be acquired through the spot market on a monthly bidding basis. For these reasons the perceptions of the major gas producers are a critical part of the evidence about the adequacy of gas supplies next winter. A number of large gas producers were asked to provide data on both their production and their contractual obligations. All specific company data provided by producers has been treated as confidential.

Respondents accounted for approximately fifteen percent of total U.S. natural gas production in 1988.[6] Based on data reported in other studies the information reported in Table 8, while not comprehensive, is representative of major oil and gas companies which are large natural gas producers.[7]

Probably the most significant aspect of change in the past decade among the major producing companies has been their strong entry into natural gas sales. This sales effort on the part of the producers was in part due to the excess production capability (the "bubble")[8] and in part to the pipeline shedding of gas reserves. Table 9 shows that committed gas sales in January 1980 were 98 percent of sales but by January 1990, only 49 percent of gas sales will be to customers who have long term commitments from the producers. As the pipelines reduced their volumes of committed gas to lower their take-or-pay contractual obligations, the producers acquired more gas that was available for short term/spot market sales. The larger short term gas supplies served to introduce a seasonal volatility in gas prices which had not been observed in the natural gas market in earlier years. Furthermore, as can be seen in Table 10, the producers expect to be direct sellers to LDC and end-users for 79 percent of their gas sales for January 1990.

Similar to the survey questions to pipelines and LDCs, the producers were asked to share their expectations regarding gas supply for January 1990, assuming that this month would be the coldest month in the past fifty years in the areas in which their gas is normally consumed. As was the case for the other segments of the industry, there was a general feeling that gas supplies were adequate for all firm customers to be served. Interruptible customers were likely to be interrupted during a severely cold month (as the hypothesized January 1990) and spot market prices would rise as they have for the past several years. This perception is essentially in agreement with earlier gas industry reports[1] and the current expectations of most pipelines and LDCs.

Table 9
Percentages of Producer January Sales of Natural Gas
1980-1990

Year	Committed Gas Sales	Spot Gas Sales
1980	98	2
1985	84	16
1988	52	48
1990	49	51

Table 10
Percentage of Producer Gas Sales By Purchaser
1980-1990
(for the Month of January)

Year	Percentage Purchased By		
	Pipelines	LDC	End-Users
1980	75	1	24
1985	78	1	21
1988	52	10	38
1990	21	25	54

Footnotes

[1] *Natural Gas - Next Winter,* A Report of the A.G.A. Gas Supply Committee, November 1988.

[2] *Executive Gas Industry Statistics,* August 1989.

[3] *Natural Gas Deliverability Study - Final Report,* Interstate Oil Compact Commission, December 1984.

[4] *Gas Energy Review,* August 1988.

[5] Joint communcation by G.H. Lawrence and J.C. Sawhill titled, *Where We Are,* July 12, 1989.

[6] *Preliminary Findings Concerning 1988 Natural Gas Reserves,* A.G.A. EA 1989-9, April 1989.

[7] *The Changing Role of Natural Gas in the Major Oil Companies,* A.G.A. EA 1989-9, September 1989.

[8] *Natural Gas Production Capability - 1989-1990,* A.G.A. IB 1989-12, July 1989.

APPENDIX I
NATURAL GAS UNDERGROUND STORAGE
(In Bcf)

		Natural Gas In Underground Storage, End of Period		
		Base Case	Working Gas	Total
1973	Total	2,864	2,034	4,898
1974	Total	2,912	2.050	4,962
1975	Total	3,162	2,212	5,374
1976	Total	3,323	1,926	5,250
1977	Total	3,391	2,475	5,866
1978	Total	3,473	2,547	6,020
1979	Total	3,553	2,753	6,306
1980	Total	3,642	2,655	6,297
1981	Total	3,752	2,817	6,569
1982	Total	3,808	3,071	6,879
1983	Total	3,847	2,595	6,442
1984	Total	3,830	2,876	6,706
1985	Total	3,842	2,607	6,448
1986	Total	3,819	2,749	6,567
1987	January	3,818	2,280	6,098
	February	3,815	1,988	5,803
	March	3,813	1,879	5,693
	April	3,812	1,938	5,750
	May	3,811	2,206	6,017
	June	3,810	2,437	6,247
	July	3,813	2,636	6,449
	August	3,813	2,836	6,648
	September	3,813	3,049	6,862
	October	3,813	3,106	6,919
	November	3,792	3,059	6,851
	December	3,792	2,756	6,548
1988	January	3,792	2,229	6,021
	February	3,791	1,827	5,618
	March	3,790	1,684	5,474
	April	3,790	1,770	5,560
	May	3,790	2,028	5,818
	June	3,792	2,293	6,085
	July	3,793	2,567	6,359
	August	3,791	2,834	6,625
	September	3,791	3,121	6,912
	October	3,792	3,243	7,035
	November	3,803	3,197	6,999
	December	3,800	2,871	6,672
1989	January	3,800	2,520	6,320
	February	3,798	2,000	5,798
	March	3,798	1,774	5,572
	April	3,792	1,825	5,617
	May	3,798	2,058	5,856

Total underground storage capacity at the end of each calendar year (in billion cubic feet): 1978-6,890; 1979-6,929; 1980-7,434; 1981-7,805 1982-7,915; 1983-7,985; 1984-8,043; 1985-8,087; 1986-8,145; 1987-8,124; and 1988-8,124. Current capacity is 8,124

Notes: Geographic coverage is the 50 States and the District of Columbia. Totals may not equal sum of components due to independent rounding. Data through 1987 are final. Subsequent data are preliminary.

Source: EIA, *Monthly Energy Review*, April 1989.

APPENDIX II

Additional Material Submitted for the Record

AGA American Gas Association

Energy Analysis

1515 Wilson Boulevard
Arlington, Virginia 22209

A.G.A. Planning & Analysis Group

EA 1989-9

September 22, 1989

THE CHANGING ROLE OF NATURAL GAS IN THE MAJOR OIL COMPANIES

Digest

This analysis examines the 12 largest holders of domestic oil reserves (Shell, ARCO, BP America, Exxon, Chevron, Amoco, Texaco, Mobil, Unocal, USX, ORYX, Phillips) and relates their statistics on oil and natural gas reserves, production and revenues to individual company strategies as well as to aggregate trends. Natural gas is increasingly important in the business strategy of these integrated "oil" giants. Certainly a company such as Amoco (the nation's largest domestic natural gas reserve holder) has made clear its commitment to natural gas. Other companies (such as Shell) have experienced growth in liquids reserves; however, Shell's domestic natural gas reserves have declined over the past five years as Shell pursued a strong gas sales program.

More of the nation's proved natural gas reserve base has become concentrated among these 12 companies since 1983. These 12 companies had 37 percent of the total U.S. reserve base in 1983 and 42 percent in 1988 (less recent Prudhoe Bay reserve write-downs). For the 12 companies as a group, revenues generated from the sales of natural gas have increased relative to revenues from liquids sales comparing 1984 with 1988. While much of this trend was caused by wellhead price variations, several companies such as ORYX (formerly Sun Exploration) have publicly expressed the desire to emphasize the natural gas segments of their business relative to oil. Changing regulatory climates and the environmental benefits of natural gas have helped advance gas to the forefront of company strategies.

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THE CHANGING ROLE OF NATURAL GAS IN THE MAJOR OIL COMPANIES

A. Introduction

The companies chosen for this analysis (Shell, ARCO, BP America, Exxon, Chevron, Amoco, Texaco, Mobil, Unocal, USX, ORYX, Phillips) are best characterized as large, international, integrated oil companies, but are also 12 of the top 15 holders of domestic natural gas reserves in the United States. Collectively, they provide over one-third of the natural gas produced in the U.S. How they have individually and collectively incorporated natural gas into their company asset structure and strategy is the focus of this analysis.

These companies are international corporate giants, which have achieved their success primarily through the exploration for and production of crude oil. These companies have made enormous investments in physical plant and human resources for liquids operations. These historic "oil pioneers" are now steadily increasing their commitment to natural gas as a fuel of the future. Changing regulatory climates, a more gas-prone domestic resource base and key national environmental issues have motivated long-term strategic business decisions toward additional development of natural gas resources for many of these large oil companies. This analysis identifies significant trends and relates recent reserve, production and revenue statistics of the subject companies to these trends.

B. Executive Summary

This examination of the 12 largest liquids reserves holders in the United States has highlighted several significant trends established by the subject companies, collectively and individually over the time period 1983-1988. Two major conclusions are developed in this analysis:

- natural gas is steadily increasing in importance to these large producers.
    - each of the top 12 largest owners of oil reserves have experienced a major shift in the source of its revenues from the sale of gas and oil at the wellhead. Revenues from natural gas are now much more important. Although oil revenues are still larger than gas revenues for each of the 12 companies, in aggregate the gas revenues have increased from 26 percent to 32 percent of the total oil and gas revenues.
- natural gas ownership is not nearly as concentrated as is the ownership of oil reserves.
    - although the domestic oil and natural gas liquids reserves of these 12 companies remained nearly

constant from 1983 to 1988, their percentage share of total U.S. reserves rose steadily from 50.2 percent to 55.3 percent. Gas reserves are much less concentrated than oil in these companies -- their share of total U.S. reserves has grown from 36.6 percent in 1983 to about 41.7 percent in 1988.

Other key developments are:

- Among the 12 companies, the average wellhead price for natural gas, oil and natural gas liquids has declined significantly since 1984. The average natural gas wellhead price dropped 31 percent from $2.45 per Mcf in 1984 to $1.70 per Mcf in 1988 for the subject companies. This compares with national averages of $2.66 and $1.71 in years 1984 and 1988, respectively. Oil prices have declined for the companies collectively, also. The average price per barrel of liquids for the 12 companies in 1984 was $24.17 declining to $12.36 by 1988. This compares to the national average domestic refiner acquisition cost of crude oil in 1984 of $28.53 and $14.76 in 1988.

- While natural gas sales price variations have been reported among the 12 companies covered in this study, this price variation has narrowed considerably since 1984. Average prices for natural gas for these major oil producers varied from $1.94 to $2.93 per Mcf in 1984 and from $1.40 to $1.89 in 1988. Compared with the national averge wellhead prices in 1984, the extremes were the Amoco average of $.27 per Mcf more and the Phillips average of $.72 per Mcf less. In 1988, the extreme variations narrowed in that Mobil and Shell were $.18 per Mcf above the national average and Phillips was $.18 per Mcf below. All others were closer to the national average. Sales to interstate pipelines showed a similar variation in the past two years, from $1.05 per MMBtu to $2.28 per MMBtu. At the low end of this range was Chevron, largely because of the Gulf-Texas Eastern warranty contract.

- The proportion of revenue derived from the sale of natural gas compared with the sale of oil and other liquids has fluctuated over the past five years for the subject companies, collectively. From a five year high of $2.93 of oil and liquids revenue for every $1.00 of gas revenue in 1987, the aggregate O/G revenue ratio for 1988 declined to $2.14 of liquids revenue for every $1.00 of gas revenue. In part, this increased earning ability for gas relative to oil has caused a change in the companies' perception of the long-term role of gas.

- Total revenues from the sale of oil and gas at the wellhead have dropped dramatically for the 12 large, integrated companies in this study. In 1984, these revenues totaled $58,195 million and by 1988 had declined to $31,843 million (a 45.3 percent drop). If examined separately, oil and natural gas liquids revenues declined 49.4 percent from 1984 to 1988, while natural gas revenues declined only 33.7 percent. For the 12 companies collectively, the decline in these revenues occurred despite increased production because of lower energy prices.

- In aggregate, the subject companies have increased their ownership of oil and natural gas reserves compared with national totals from 1983-1988. In 1983, the companies held 36.6 percent of proved gas reserves. That increased to 41.7 percent by 1988. The same companies held 50 percent of all domestic proved oil and natural gas liquids reserves in 1983 and 55 percent by 1988.

- The balance of oil to gas reserves on a Btu basis for the 12 companies, collectively, has remained virtually unchanged since 1983 at 61 percent oil and other liquids and 39 percent natural gas.

- The ranking of the companies' oil reserve holdings (i.e., largest, second largest, etc.) over the 1983-1988 time period has been relatively static. Most changes in ranking were in the top four companies: Shell (rising); ARCO (rising); BP (falling); and Exxon (falling). The ranking of the companies' gas reserve holdings over the same period showed Amoco displacing Exxon as the largest reserve owner and the dramatic growth of Chevron from eighth place in 1983 to third place in 1988.

- Six of the 12 companies examined increased their liquids reserves from 1983 to 1988. A different group of five companies of the 12 increased natural gas reserves over the same period. In aggregate, liquids reserves ownership increased 8.3 percent from 17,890 million barrels to 19,381 million barrels, while natural gas reserves increased 9.0 percent from 64,248 Bcf to 70,032 Bcf.

- All companies acknowledge the environmental advantages of natural gas over other fossil fuels. Yet, new demands for natural gas and the changing regulatory climate are causing natural gas issues related to pricing and distribution to be resolved by market forces.

C. Methodology

It is difficult to compare the non-uniformly reported statistics of these 12 different companies. Statistics compared in this study are the proved reserves of oil, natural gas liquids and natural gas, production of these products and the revenue generated from their production. In order to accommodate the variety of reporting methods and styles, numerous editorial decisions to group the hydrocarbon reserves and compute the resulting revenues from company sales were made.

First, natural gas liquids reserves were added to that of oil reserves as was natural gas liquids production to oil production. Many companies report liquids reserves and production undifferentiated. Thus, adding those reported separately matches well with those reported undifferentiated. Natural gas reserves and production were typically reported as a separate entity from other hydrocarbons and were therefore not a grouping problem.

Second, these companies often report their revenues differently. More important than the dollar values of revenues in this study are the ratios developed from the sales of natural gas compared to oil and natural gas liquids. To compare the revenue sources, it was decided to determine the average weighted selling price of a particular type of hydrocarbon sales for a given year (normally given in the annual report) and multiply the price and the reported production of that hydrocarbon. This then, is an approximation of revenues from the sale of hydrocarbons by each company (see Table 3), but puts these values on comparable bases. Where possible, production and prices for natural gas liquids were determined separately from those of oil, then added to oil revenues.

The oil-to-gas (O/G) revenue ratio was then determined by dividing oil revenues (plus natural gas liquids) by natural gas revenues. A value of one would imply that revenues from the sale of liquids equaled those from the sale of gas. A value less than one would imply that gas revenues were larger. In reality, all ratios were greater than one, indicating that oil revenues have been larger than gas revenues for the 12 companies. However, significant changes have occurred since 1983, and indeed, all companies appear to be increasing the relative amount of gas revenue to oil revenue over that time period (i.e., ratios are becoming smaller, moving from 3.0 toward 2.0). This phenomenon is due to changes in production levels and the relative price decline of oil and gas liquids. Liquids prices have declined more sharply over the study period than natural gas prices.

Again, the revenues listed in Table 3 are not intended to accurately represent all revenues attributable to the sales of a particular hydrocarbon by any particular company. Prices reported by individual companies are difficult to make absolutely comparable. Natural gas used in production processes is also included in the revenue computations of the companies. Rather than focus on the actual revenue values, comparison of oil/gas revenue ratios over time is the best use of the data presented.

In order to fairly and consistently compare individual company reserve statistics to national totals (such as in Table 6), certain assumptions must be clearly identified. Specifically, the definition of total U.S. gas reserves for the purposes of this study must be understood. Certain companies (Exxon, BP and Arco) have written most of their Prudhoe Bay gas reserves off their books because of a lack of adequate transportation facilities from the North Slope. In doing so, they are reporting company reserves in terms of lower-48 states reserves plus some net of Alaskan reserves (Alaskan gas reserves less most Prudhoe Bay gas reserves). To compare any individual company's gas reserves to national totals, the total U.S. natural gas reserves for any given year are reduced by the EIA estimate of the Alaskan North Slope write-down (24,613 Bcf).

It is also important to note that part of the increase in oil and natural gas reserves (particularly in 1988) observed since 1983 has come from the purchase of large quantities of reserves by several of the twelve reserve holders in this study. More specifically, Amoco, Arco and Chevron can attribute large portions of their reserve increases from 1987 to 1988 to purchases of portions of Tenneco's oil and gas properties in 1988.

Data presented in Table 7 is not intended to represent all sales of natural gas by the subject companies. Table 7 instead is an attempt to identify large purchasers of interstate pipeline gas from the listed producers and the geographic areas in which the sales originate. The data presented are not annual totals but relate only to the dates specified in the table. Thus, the data is a "snap-shot" of interstate pipeline sales.

The data accumulated and anecdotal evidence for certain conclusions in this study are drawn from individual company annual reports, SEC Form 10Ks, personal correspondence from company representatives, EIA reports and the Foster Bulletin on Deregulated Gas. Much of the data reported is subject to company-specific operating conditions. As a result, this study does not attempt to analyze any individual company's response to industry-wide trends. This analysis instead focuses on identifying specific industry trends, then reports companies' statistics related to the changing climate of the gas industry.

D. Aggregate Analysis

The companies analyzed in this study are for the most part integrated corporations with primary business activities involved in the discovery, development, refining and distribution of hydrocarbons and petroleum products. Generally, they are viewed as "oil" companies. In fact, the 12 companies chosen for this study are the 12 largest holders of domestic oil reserves in the United States. Each has in excess of 400 million barrels of oil and natural gas liquids in proved reserves. Table 5 enumerates the oil reserve data and identifies the companies in this study. However, the companies also are major holders of gas reserves (see Table 4) and the accumulation and subsequent sale of natural gas and gas by-products has become an increasingly visible portion of their business and business strategy. This analysis focuses on the aggregate and individual company changes and trends visible in the domestic natural gas segment of their businesses, particularly during the past five years (1984-1988).

Oil and Natural Gas Prices

Table 1 lists the average weighted price received by individual companies from 1984-1988 for oil (including natural gas liquids) and natural gas. Figure 1 illustrates the range of prices for natural gas over the same time period. The table shows that while the average price for these companies in aggregate for gas has dropped from $2.45 per Mcf in 1984 to $1.70 per Mcf in 1988 (a 31 percent decline), the price of liquids for the same companies declined 49 percent. However, on a Btu basis, natural gas remains less expensive. At the pricing maximum in 1984, natural gas cost $2.38 per MMBtu while liquids cost $4.17 per MMBtu. At the lower price levels exhibited in 1988, the gap between natural gas and the average liquids price narrows. Natural gas cost $1.65 per MMBtu as compared to the average liquid price of $2.13 per MMBtu.

Price has played an important role in strategic decisions regarding future inventories of natural gas for the subject companies. Some companies view an era of low domestic wellhead prices and accompanying lower industry service costs as an opportunity to increase domestic inventories through exploration or acquisition of reserves at relatively low cost. Others view low domestic price as a signal to emphasize exploratory activities overseas where economic returns may be substantially greater. Whatever their philosophy, some facts remain. Phillips, which produced 312 Bcf in 1988 (ninth place in our sample of 12 companies), had almost the lowest weighted average domestic gas price of $1.53 per Mcf. Mobil and Shell (the fourth and sixth largest producers, respectively, in terms of volume) had the highest gas price of $1.89 per Mcf for domestic production. The average weighted selling price for all the companies was $1.70 per Mcf in 1988, up from $1.59 per Mcf in 1987.

Table 2 compares the average natural gas prices received by the producers and the national average wellhead prices for each year from 1984 to 1988. Several observations can be made. First, of the 60 price comparisons shown, only 21 showed the major oil producers receiving prices above the national average. In two cases the prices were the same and in 37 cases the national average price was greater than the major oil producer's prices. Interestingly, one producer (Phillips) received less than the national average in each year from 1984 to 1988. Two companies sold gas above the national average each year; they were Shell and Amoco. The latter two companies accounted for 7.1 to 8.1 percent of total U.S. production from 1984 to 1988.

Table 7 describes sales prices (in $ per MMBtu) to interstate pipelines for various six-month time periods from 1987-1988 as reported by Foster Associates in January 1989; Table 1 contains data for an earlier time and is quoted in $ per Mcf. Direct comparisons from one table to the other require that the prices be converted; the time difference is also a significant variable. Even so, Unocal, Mobil, Arco, Shell, USX, Exxon, ORYX, Amoco, Phillips, Texaco and Chevron is the descending order (i.e., Unocal the highest price; Chevron the lowest) of price for the interstate market. In contrast, for total sales in 1988 the descending order of prices paid is Shell, Mobil, Amoco, Unocal, Exxon, Texaco, Arco, ORYX, Phillips and Chevron. In these data, Shell and Mobil are at the higher end and Phillips and Chevron are at the lower price end.

Revenue Comparisons

For each company from years 1984 through 1988, revenues from the sale of oil and gas were calculated and compared (see Table 3). The volatility of prices in past years for oil and natural gas make comparisons of the dollar amounts less important than the ratio of oil revenues to gas revenues over time. Without question, revenues received at the wellhead by individual companies and the 12 in aggregate have declined significantly since 1984 (see Table 3 totals). But interestingly, every company, with the exception of Amoco, has increased the amount of revenue generated at the wellhead by gas relative to that of oil and natural gas liquids since 1984. In aggregate, the 12 companies had an O/G revenue ratio of 2.81 to 1 in 1984. By 1988, the ratio had declined 24 percent to 2.14 to 1. Though more revenue is still generated by oil for these companies, sales of natural gas at the wellhead have taken on a more significant role in recent years. Amoco's O/G revenue ratio is essentially the same in years 1985 and 1988; however, the 1988 ratio of 1.72 to 1 is down from the 1987 ratio of 2.15 to 1.

Reserve Ownership

One feature of this analysis is to discover and compare any changes in ownership of reserves among the 12 companies examined. Some relationships remain unchanged, while others have changed significantly. For example, the 12 companies in aggregate held 70,032 Bcf of natural gas reserves in 1988. This volume has increased 9 percent since 1983 (see Table 4). In addition, the concentration of reserves held by the 12 companies compared with total U.S. proved reserves has increased. Figure 2 illustrates the concentration of gas and oil reserves held by the companies since 1983. Figure 3 illustrates the range of reserves held individually by the 12 companies. In 1983, 37 percent of natural gas reserves in the United States were held by the 12 companies. By 1988, the companies owned 42 percent of the nation's proved gas reserves, a 5 percent increase. The subject companies have also increased their percentage ownership of oil reserves during the same period from 50 percent to 55 percent of the U.S. total.

However, individually only five companies -- BP America, Arco, Chevron, Amoco and Mobil -- have actually increased their proved gas reserves since 1983. The seven remaining companies have lost reserves. Two companies in particular, Amoco and Chevron, have significantly increased their ownership of gas reserves in the United States since 1983. By contrast, six of the companies (Shell, Arco, Chevron, Amoco, Texaco and Mobil) have increased the volume of oil reserves held (see Table 5).

Table 6 shows that on average the subject companies each hold 1,615 million barrels of oil (4.6 percent of the U.S. total) and 5,836 Bcf (3.5 percent of U.S. total) as proved reserves on a volume basis. On a Btu basis, this implies that the average large integrated oil company holds reserves made up of 61 percent oil and 39 percent natural gas. This has remained unchanged since 1983. With respect to production on a Btu basis, this sample of large petroleum producers has annually produced 64 percent of their total production from oil and other liquids and 36 percent in the form of natural gas since 1983.

As is the case with the above reserves information, aggregate statistics of key parameters may reflect some industry-wide trends, but it often masks significant changes in individual company performance. For example, the 12 subject companies increased their gas reserve holdings 9 percent (64,248 Bcf to 70,032 Bcf) from 1983 to 1988, yet Chevron increased its gas reserves 70 percent during the same time period, while Shell decreased its gas reserves by 16 percent. These statistics underscore the independent operations of each company and that individual company statistics often do not reflect the industry-wide trends.

E. Individual Company Analysis

Shell Oil Company (Shell)

At year-end 1988, Shell Oil Company was the largest holder of petroleum liquids reserves in the United States. It was also the sixth largest holder of natural gas reserves at 6,248 Bcf. In addition, Shell held the distinction of drilling 883 wells in 1988, more than any other company. Most were development wells (827), however, 15 exploratory wells were drilled as were 41 dry holes. Shell invested $2.0 billion in capital expenditures for oil and gas exploration and development in 1988, up $500 million from 1987. At year-end 1988, 1,271 of Shell's 20,842 producing oil and gas wells (or 6 percent) were gas wells. Shell's 1988 drilling program resulted in additions of 43 million barrels of liquids and 426 Bcf to reserves through extensions and discoveries.

Since 1983, Shell's total gas reserves have declined 16 percent from 7,434 Bcf to 6,248 Bcf, while oil and other liquids reserves have increased 32 percent. During the same time period, the natural gas R/P ratio has declined 22 percent from 13.79 to 10.75. Gas production has fluctuated from 539 Bcf in 1983 to 656 Bcf in 1987. Table 7 shows that, for six month data reported in January 1989 by Foster Associates, Shell sold over 57 percent of its production sold to interstate pipelines to three companies -- Florida Gas Transmission (July-December 1987), El Paso Natural Gas (July-December 1987) and Transcontinental Pipeline (October 1987-March 1988). Over 70 percent of these sales were from gas produced from the Gulf of Mexico. Indeed, Shell's biggest concentration of natural gas reserves and production is in the Gulf of Mexico, where 56 percent of its entire 1988 gas production originated. As a result, Shell's natural gas prices tend to be high, ranking close to the highest in each of the categories listed in Tables 1, 2 and 7.

Shell has strengthened its natural gas marketing in response to deregulation of various industry facets in recent years. Shell's commitment to gas can be seen by its intent to purchase a part ownership in the Cove Point, Maryland, LNG facility. Shell also recognizes the likelihood of volatile natural gas and oil prices in the future. Shell has exercised a strategy of a broad hydrocarbon exploration program both in relatively low risk basins (such as Michigan) and potentially higher yield locations such as offshore Alaska and the deepwater plays of the Gulf of Mexico.

In fact, Shell holds interest in 770 tracts of offshore properties in the western, central and eastern Gulf of Mexico, more than any other company. The company has made significant capital investments in projects such as Bullwinkle (the world's tallest fixed offshore structure) in the Gulf of Mexico. At its peak, this platform will produce 44,000 barrels per day and 100 MMcf per day. Onshore, Shell has concentrated primarily in California, West Texas, the Gulf Coast and Michigan.

Table 3 shows that Shell has increased its proportional share of revenue derived from gas sales compared with sales of liquids, since 1983. In 1983, nearly three dollars of oil revenues were received by Shell for every one dollar of gas revenue. That is, for the calculated annual revenues examined for Shell in this study, in 1983, 25 percent were from gas sales and 75 percent were from oil and liquids sales. By 1988, gas sales accounted for 32 percent of this annual revenue stream. Much of this proportional increase is due to a severe drop in the price of oil received by Shell since 1983 compared with a lesser drop in the price of natural gas paid to Shell. In fact, Shell received among the highest prices for its produced gas for the companies in this study.

On the surface, Shell seems to be maintaining its role as a major "oil" company with its greatest reserve addition successes coming in the form of oil and other liquids in recent years. However, increasing relative revenues from gas sales, as well as long-term strategic decisions such as investment in LNG facilities, seem indicative of Shell's commitment to gas as a primary asset for the future.

ARCO

ARCO is one of the five companies that has increased its natural gas reserves since 1983, among the 12 companies examined in this study. In fact, ARCO has increased its natural gas reserves 10.0 percent, from 5,795 Bcf in 1983 to 6,373 Bcf in 1988. These reserve totals do not include 8,300 Bcf (associated-dissolved gas reserves on Alaska's North Slope) removed from ARCO's books until gas transportation facilities are developed from the North Slope. Coincidentally, ARCO has increased its liquids reserves 10 percent since 1983. Production for both natural gas and liquids has remained stable over the past six years. Liquids production has been about 240 million barrels per year with a R/P ratio of 11.5, while natural gas production has approximated 550 Bcf annually (R/P ratio of 10.9).

ARCO has aggressively moved to solidify its reserve position through natural gas discoveries and acquisitions. Beginning in 1987, ARCO made an exciting Arbuckle Limestone discovery and subsequently delineated 500 to 600 Bcf of gas reserves in the Arkoma basin of southeastern Oklahoma (Latimer County). ARCO has also pursued development of coal seam gas in the San Juan basin. In 1988, ARCO purchased Tenneco's California oil and gas properties. These activities have created excess deliverability capability in spite of high sales volumes. ARCO continues to seek new markets for its expanding production capability.

ARCO has sought to expand its production base geographically. Currently, over half of ARCO's lower-48 states gas production originates in the Gulf of Mexico. Table 7 shows that for various six-month time periods in 1988, nearly 70 percent of ARCO's production that was sold to interstate pipelines originated from the Gulf of Mexico. Revenues from oil and gas production are also more evenly spread in 1988 as opposed to 1984. In 1984, ARCO's oil/gas revenue ratio was 3.39. That ratio had declined to 2.46 by 1988. Much of that relative decline can be attributed to a drop in the average oil price paid to ARCO of 48 percent in that time period, while natural gas prices dropped 35 percent.

Regardless of the relative evidence of ARCO's commitment to natural gas, ARCO stands as the fifth largest gas reserve holder in the United States. This position implies that it is poised to grow with the market opportunities created by environmental concerns, regulatory adjustments and adequate supplies.

BP America

BP America is another company that envisions natural gas as a key area of corporate growth, considering the climate of regulatory changes and environmental concerns leading into the 1990s. BP America also anticipates an evaporation of the "gas bubble," experienced industry-wide throughout the 1980s, by the early 1990s.

BP America was formed after British Petroleum (BP) acquired Standard Oil of Ohio (SOHIO). Along with significant oil reserves (primarily from Alaska's North Slope), BP incorporated an expanding gas reserve base into its U.S. reserve holdings. Natural gas reserves have grown 50 percent from 1,512 Bcf in 1984 to 2,273 Bcf in 1988. Excluded from these "booked reserves" are 5,661 Bcf located on the Alaskan North Slope. Like the North Slope gas reserves held by ARCO and Exxon, these BP America assets will be developed when transportation facilities are made available.

Historically, BP has emphasized oil production over natural gas production. However, world-wide, BP now holds about 28 percent of its reserves (on a Btu basis) in the form of natural gas. This is up from only 19 percent five years ago. In the United States, revenues, though still heavily oil-oriented (see Table 3), have increased steadily from the sale of natural gas (an estimated 25 percent increase since 1983). Indeed, BP America holds more natural gas reserves in the United States than ever before and will probably be a key supplier to future developing markets. For example, BP America expects gathering volumes and production to more than double by the early 1990s.

Exxon

Exxon is the fourth largest holder of domestic oil reserves (2,630 million barrels) and the second largest holder of domestic natural gas reserves (9,341 Bcf) in the United States. Exxon has dropped from its books 7.8 Tcf of North Slope reserves because of a lack of adequate transportation facilities in Alaska; otherwise, Exxon would be the largest natural gas reserve holder in the United States. For the 1984-1988 period considered in this study, Exxon has been the leader in total annual revenues from oil and gas.

Reserves have remained relatively stable for Exxon in the past five years, declining only 8 percent from the most recent high reserve year of 1986. However, production has experienced a sharper decline from 977 Bcf annual production in 1984 to 751 Bcf in 1988. Foster Associates data for early 1989 indicate that 67 percent of Exxon's sales to interstate pipelines originated from Louisiana offshore and southern onshore locations.

Table 3 shows that Exxon earned, in 1988, $2.31 from sales of oil and other liquids for every $1.00 earned from gas sales at the wellhead. This ratio of oil to gas earnings is down from 3.16 in 1984. A greater relative change in the price of crude oil than that of natural gas is the greatest contributor to the change in earnings ratios. In addition, Table 1 shows that in 1988, Exxon received on average less than the total 12 company group for a barrel of crude oil, but slightly more for natural gas ($1.80 per Mcf compared to a group average of $1.70 per Mcf). When Exxon gas prices are compared to the national average, Exxon prices were well below ($.50 per Mcf) the national average in 1984 but rose to $.09 per Mcf above in 1988.

Without question, Exxon is a giant among U.S. integrated petroleum companies. In the recent past, Exxon has positioned itself as a major natural gas reserve holder and producer through exploration and acquisition expenditures. Exxon explores for hydrocarbons in every prominent geologic basin at all prospective depths in the United States. The company is well positioned to deliver incremental increases in gas production when market conditions demand it.

Chevron

Since 1983, Chevron has aggressively increased reserves of oil and natural gas in spite of volatile wellhead prices and changing markets. In fact, through both exploratory expenditures and acquisitions (notably the acquisition of Gulf Oil in 1984 and the recent acquisition of Tenneco's Gulf of Mexico properties for $2.5 billion) Chevron has increased proved reserves 70 percent from 4,877 Bcf in 1983 to 8,274 Bcf in 1988. Chevron also anticipates continued growth in gas production as a result of the purchase of Tenneco's Gulf of Mexico properties in 1988.

The significant increase in natural gas reserves is paralleled by increases in liquids reserves since 1983. Between 1983 and 1985, liquids reserves were increased 906 million barrels from 1,182 to 2,088 million barrels. Since 1985, liquids reserves have dropped 13.5 percent to 1,806 million barrels, yet Chevron still ranks fifth among U.S. liquids reserve holders.

Chevron recognizes gas as the environmentally preferable fuel of the future. Certainly, major acquisitions in recent years point to Chevron's commitment to accumulating and producing natural gas reserves. In recent years, Chevron has emphasized exploration and development of properties in the Gulf of Mexico, Texas, Oklahoma, the Rocky Mountains, California's San Joaquin Valley and Alaska. Approximately 38% of Chevron gas sales at the wellhead go to interstate pipelines. Table 7 shows that company sales attributable to interstate pipelines', as reported by Foster Associates in January 1989, originated primarily from the Louisiana offshore, but significant volumes also came from various Rocky Mountain and New Mexico locations. All of the Chevron prices quoted in this paper are low compared with other producers primarily because much of Chevron's sales came from regulated gas averaging .80 per MMBtu. Much of this gas was sold under the warranty gas contract, which Gulf had with Texas Eastern.

Chevron exhibited an O/G revenue ratio of 2.13 in 1988. This was down from 2.82 in 1984. This occurred even though Chevron received one of the lowest average selling prices for its natural gas at the wellhead among the 12 companies ($1.40 compared to the 12-company average of $1.70 in 1988). In 1985, the revenue ratio was 3.18 (partly because of relatively high crude oil prices). However, a revenue balance more like that of 1988 is likely for Chevron in the future, particularly in light of the impending expiration of the Texas Eastern warranty contract, growth in reserves and expectations of the environmental preeminence of gas in the nation's energy mix.

Amoco

Without question, Amoco has demonstrated its commitment to natural gas in the United States since 1983 and before. Amoco is the largest owner of natural gas reserves in North America and leads the 12 company group with booked U.S. reserves of 12,371 Bcf at year-end 1988. Amoco has increased reserve holdings every year since 1983, resulting in a 32 percent increase over that time period. In 1988, Amoco added nearly 2.3 Tcf of gas reserves with 1.4 Tcf coming from purchases and other acquisitions (primarily Tenneco's Rocky Mountain properties) and over 500 Bcf coming from discoveries and extensions. Amoco's liquids reserves have remained steady at about 1,700 million barrels since 1983 (see Table 5).

Amoco conducted a vigorous drilling program (second only to Shell) in 1988. Amoco drilled 607 wells in 1988 with an 85 percent success rate. Exploratory wells accounted for 21 percent (128 wells) of all of Amoco's U.S. wells drilled. Of those companies reporting such statistics, Amoco has the most producing gas wells (10,194 wells), accounting for 34 percent of all Amoco wells in the United States. Amoco has significant leasehold in the Gulf of Mexico including Mobile Bay, the Rocky Mountains, the Mid-continent, and has been a leader in coalbed methane development in the San Juan basin of New Mexico and the Black Warrior basin of Alabama. In short, Amoco has aggressively diversified its exploration and development activities to most prominent natural gas plays in the U.S. lower-48 states and beyond.

Amoco has been flexible during the development of changes in gas markets in recent years. In 1983, sales to end-users accounted for only 4 percent of natural gas sales. By 1988, end-user sales had increased to 33 percent of total Amoco natural gas sales. Table 7 and Figure 5 indicate that Amoco's production sold to interstate pipelines is evenly spread among geographic areas such as the Louisiana offshore, Kansas and the Rocky Mountain states.

Revenues from natural gas sales have traditionally been a significant part of the total hydrocarbon sales of Amoco . The 1988 O/G revenue ratio of 1.72 is comparable to the ratios in 1986, 1985 and 1984. In the past five years, only 1987 was an annual period when the revenue ratio exceeded 2.00 (2.15). Additionally, in 1988 Amoco received on average $1.87 per Mcf at the wellhead as opposed to the 12-company average of $1.70 per Mcf. Similarly, Amoco gas prices were $.05 to $.27 per Mcf above the national average from 1984 to 1988.

Currently, Amoco owns nearly 7 percent of all proved gas reserves in the United States -- the largest for any one company. With a reserve to production ratio of greater than 20, Amoco obviously believes in the long-term future of natural gas as a company asset. Capital investments, drilling activity, acquisitions and an expanding reserve inventory are testament to Amoco 's position as an aggressive gas producer in the United States.

Texaco

For the purposes of this study, Texaco offers extreme as well as average statistical input from which to be analyzed. For example, Texaco was the largest producer of natural gas in 1988 at 780 Bcf, yet had by far the lowest reserves to production ratio of any company in this study (5.98). However, Texaco sold its gas at the wellhead ($1.72 per Mcf) for nearly the 12-company average of $1.70 per Mcf in 1988 - just $.01 per Mcf above the national average.

Texaco has been the largest producer of natural gas among the 12 companies three of the last four years (1985-1988). In 1987, Texaco reported that 4,034 of the company's 42,095 producing wells were gas wells (9.6 percent). Many of those wells are located along the Gulf Coast including Louisiana and Texas state waters and federal waters in the Gulf of Mexico. Recent drilling activity has been most prevalent in the Gulf Coast, Rocky Mountain and Mid-continent regions. Texaco has chosen to reduce exploratory risks in the United States by joining joint ventures and by drilling less risky geologic prospects. This may account for modest additions to reserves through discovery and extensions, particularly the past three years (1986-1988).

Texaco's R/P ratio has been below 7 since 1984 and in 1988 was the only company among the 12 with an R/P ratio even below 9. However, revenues from natural gas sales have become increasingly important to Texaco as illustrated in Table 3 by Texaco's 1988 O/G revenue ratio of 1.82. The revenue ratio is down from 2.52 in 1987 due primarily to continued declining liquids prices and firming natural gas prices. In fact, Texaco is directing new natural gas sales initiatives toward industrial end-users, specifically those located along the lower Mississippi River.

In recent years, Texaco has benefited from the cash flows generated by high volume natural gas sales. And, although liquids reserves have remained steady the past three years (1986-1988), natural gas reserves have fallen. Texaco's production is already down 17 percent from the recent annual high of 944 Bcf in 1984. To remain a premier producer of natural gas in the United States, Texaco will need to replace reserves at accelerated rates compared to recent annual performances.

Mobil

Mobil has remained a "big play" strategist among the 12 companies in this study throughout the recent period of price volatility and fluctuating economics. That is, Mobil has concentrated its exploration efforts on being a large prospect hunter, mainly offshore, with some outstanding results such as the discovery of Mary Ann field in Mobile Bay. Such an approach is the antithesis of that utilized by other companies of reducing risks in times of price and other economic uncertainties. This strategy has contributed to Mobil's position as the fourth largest holder of natural gas reserves in the United States. Natural gas reserves have leveled since 1984, dropping only 7 percent, from 8,084 Bcf in 1984 to 7,515 Bcf in 1988. Reserves remained strong in 1988 even though production was at a six-year high of 658 Bcf. Mobil's liquids reserves picture has also remained positive. In fact, crude oil and natural gas liquids reserves have actually increased 10 percent since 1984 (see Table 5).

Aside from maintaining spending levels for exploration, Mobil, like other major producers, has dedicated funds for scientific improvements in technology inputs related to geologic interpretation activities. For example, Mobil has demonstrated major technological advances in both offshore seismic exploration and computer based geostations for geologists and engineers.

Mobil has for the past six years enjoyed significant contributions to income from the sale of both liquids and natural gas. In fact, Table 3 shows that in 1988 Mobil had the O/G revenue ratio at 1.11. During the period covered by this analysis (1983-1988), Mobil's O/G revenue ratio has not exceeded 1.95. In 1988, Mobil also received the highest price for gas at the wellhead among the 12 companies of $1.89 per Mcf (duplicated by Shell). A similar situation was reflected in Table 2, which shows Mobil and Shell prices in 1988 to be $.18 per Mcf above the national average. Mobil's interstate pipeline sales were also among the highest cost.

These factors, along with changes in the natural gas regulatory arena, have created an opportunity to, as Mobil states in its 1988 annual report "grow with natural gas." Already, Mobil sells 80 percent of production directly to end-users and has become committed to the role of downstream natural gas marketer. Table 7 indicates that half of Mobil's production to interstate pipeline companies originates from the Gulf of Mexico. Continued access to growing markets, exploration and development successes and historically high production rates may elevate Mobil even higher as one of the prominent natural gas producers in the United States.

Union Oil Company of California (Unocal)

Unocal is the eighth largest holder of natural gas reserves in the United States. The company is similarly positioned as the ninth largest holder of liquids reserves, domestically. Since 1983, Unocal has maintained a natural gas reserves to production ratio of nearly 15 or greater, well above the 12-company average of slightly below 12. Natural gas reserves have declined 14 percent from 5,049 Bcf in 1983 to 4,320 Bcf in 1988, however, production was also down 15 percent in 1988 (276 Bcf annually) from a six-year high of 325 Bcf in 1984.

Unocal has traditionally maintained a strong exploratory and development acreage position in onshore and offshore California and the Gulf of Mexico. In fact, Unocal acquired 263,554 net acres in 77 Gulf of Mexico tracts in 1988 alone. Frontier areas of Alaska have also attracted Unocal's interest.

The company's O/G revenue ratio declined to 1.42 in 1988 from 2.06 in 1985. Disproportionate declines in prices received for liquids as opposed to natural gas contributed to the revenue ratio change. However, Unocal did receive better than the 12-company average of 1.70 per Mcf at the wellhead for natural gas, by averaging $1.81 per Mcf in 1988.

Considering the relatively high reserve to production position of Unocal and recent demonstrated production levels 15 percent greater than 1988 levels, the company is well positioned to make natural gas an even greater part of its energy outflow, if market conditions allow it.

USX

In an effort to diversify its business segments, USX purchased first Marathon Oil, then Texas Oil and Gas (TXO) in the 1980s (see Appendix A). These acquisitions provided USX with significant reserve holdings of oil and natural gas in the United States. From a peak in 1985, natural gas reserves have declined 16 percent to 3,048 Bcf and liquids reserves have declined 5 percent to 596 million barrels in 1988. Production levels of natural gas have remained steady in recent years; coupled with slightly declining reserves, the natural gas R/P ratio dipped below 10 for the first time during the period 1983-1988 in 1988.

Relative earnings from oil and natural gas have fluctuated significantly in recent years for USX. In 1987, the O/G revenue ratio for USX was 2.42, dropping to 1.54 in 1988. The emphasis on gas production in 1988 was equally shared by Marathon and TXO with Marathon producing 442 MMcf/d and TXO producing 414 MMcf/d (its fourth highest production rate in company history). The average wellhead price of gas production was below that of the 12-company average ($1.70 per Mcf in 1988) at $1.57 per Mcf.

USX believes that successful strategy in the 1990s will include reduction of costs to limit downside risks associated with volatile crude oil and natural gas prices. However, commitments to exploration and development projects for reserve replacement, aggressive marketing and upgrading of transportation systems are necessary for continued growth.

ORYX

ORYX (formerly Sun Exploration Company) believes that key environmental issues and resulting legislation will place natural gas at the forefront of energy sources to meet incremental increases in demand for energy into the 1990s. To accommodate this view, ORYX plans to add natural gas reserves in sufficient volumes to change the company's current reserves mix (on a Btu basis) of 63 percent oil and 37 percent gas to a 50/50 relationship. As an outgrowth of this effort, ORYX plans to increase natural gas marketing efforts to end-users (a strategy employed successfully by companies such as Mobil).

The recent formation of a separate upstream exploration and development company from the Sun company is part of an effort to refocus attention to reserve replacement of both liquids and natural gas. From a recent high of 745 million barrels (1984), liquids reserves have declined 20 percent to 594 million barrels in 1988. Gas reserves have declined even more abruptly, from 2,931 Bcf in 1983 to 2,239 Bcf in 1988 (a 24 percent decrease). Production of natural gas has also declined 25 percent since 1983, leaving ORYX with a natural gas reserves to production ratio of 11.08 (slightly less than the 12-company R/P ratio of 11.84). Figures from 1987 indicate that 18 percent of ORYX's producing wells (1,495 of 8,176 wells) were gas wells.

Revenues from the sale of liquids and natural gas resulted in an O/G revenue ratio of 2.14 in 1988 (precisely the O/G revenue ratio of the 12 companies, collectively). That is a significant change from previous years such as 1985 when the ratio was 3.07. Much of the proportional change is due to sharper declines in oil prices, yet ORYX received less than the twelve company average price of $1.70 per Mcf at the wellhead for its natural gas production ($1.59 per Mcf in 1988).

ORYX has stated its commitment to natural gas and its commitment to increasing natural gas reserves. It will be several years before the success of the outlined strategy can be assessed.

Phillips Petroleum Company (Phillips)

Phillips is the 12th largest holder of oil and natural gas liquids and the ninth largest natural gas reserve holder in the United States. Phillips is also the largest producer of natural gas liquids in the country. In 1988, 27 percent of Phillips' 10,013 producing, domestic wells were natural gas wells. And, although gas wells have remained stable at just over 2,700 producers over the past five years, oil producers have declined from 9,207 in 1984 to 7,292 in 1988. Correspondingly, oil and natural gas liquids reserves have declined 19 percent since 1983, while natural gas reserves have declined only slightly more than 1 percent.

Phillips' O/G revenue ratio has dipped dramatically towards 1 since 1984. In 1984, the O/G revenue ratio was 2.35. By 1988, that ratio was 1.13 indicating that Phillips was earning nearly the same amount of revenue from the sale of natural gas as that earned from the sale of liquids. This leveling of revenues occurred even though Phillips' natural gas price per Mcf of $1.53 at the wellhead was the lowest of the 12 companies or compared with the national average. The combination of geographic locations and emphasis on key producing plays are responsible for Phillips low prices relative to other companies. Tables 1, 2 and 7 show that the average price for Phillips natural gas production was consistently below that of the other companies in aggregate for the five-year period 1984-1988.

Phillips plans to direct 42 percent of its capital expenditures in 1989 toward exploration and development projects. Major portions of these expenditures are for development programs offshore in California and in the Gulf of Mexico and the Permian basin. A short-term strategy of exploration and production is to develop existing discoveries that can be brought onstream quickly to generate and sustain cash flows. Securing additional reserves in stable parts of the world is a long-term strategy for Phillips Exploration and Production.

Table 1
Average Weighted Selling Price of Crude Oil and Natural Gas (U.S.)
1984-1988

		Oil[1] ($/BBl)					Natural Gas ($/Mcf)				
Company	Rank*	1988	1987	1986	1985	1984	1988	1987	1986	1985	1984
Shell	(11)	12.46	15.51	13.20	24.55	26.00	1.89	1.85	2.17	2.74	2.80
ARCO	(5)	10.08	12.55	9.09	19.01	19.35	1.68	1.63	1.94	2.52	2.58
BP America	(6)	10.20[e]	12.30[e]	7.56[2]	17.15[2]	18.03[2]	1.70[e]	1.45[e]	1.58[2]	2.45[2]	2.67[2]
Exxon	(8)	11.22	15.39	10.54	22.17	22.64	1.80	1.79	2.01	2.59	2.16
Chevron	(1)	12.45	14.83	11.78	24.78	25.51	1.40	1.35	1.69	2.18	2.35
Amoco	(10)	13.48	16.49	14.22	22.03	22.86	1.87	1.73	1.99	2.76	2.93
Texaco	(7)	12.72	14.84	13.62	23.42	25.29	1.72	1.55	1.86	2.22	2.22
Mobil	(11)	12.48	15.25	13.37	24.25	25.03	1.89	1.77	1.96	2.39	2.43
Unocal[3]	(9)	11.90	14.77	12.51	23.31	25.03	1.81	1.63	1.94	2.21	2.29
USX	(3)	13.35	16.09	13.37	24.96	26.67	1.57	1.41	1.74	2.32	2.57
ORYX	(4)	14.61	16.77	14.71	25.54	27.33	1.59	1.49	1.81	2.47	2.50
Phillips[3]	(2)	13.41	16.35	13.83	24.56	26.25	1.53	1.45	1.64	2.06	1.94
Average[4]		12.36	15.10	12.32	22.98	24.17	1.70	1.59	1.86	2.41	2.45

[e] Estimated.
*Rank order from 1 - 1988 lowest gas sales price to 11 - 1988 highest gas sales price.
[1] Domestic oil and natural gas liquids.
[2] Data reported from Standard Oil of Ohio.
[3] Excludes natural gas liquids.
[4] $/Mcf or $/bbl.

NOTE: Data for this table is derived from Company Annual Reports, Form 10Ks and personal communications. Because companies report prices differently, for example prices may be reported as wellhead, gathering system or processing plant sales, the actual prices may not be absolutely comparable between the companies. However, the prices do reflect real trends over time for any individual company. The reader should refrain from direct comparision of prices between the companies in this table.

Table 2

Comparison of Company and National Average Wellhead Price for Natural Gas (in $/Mcf)

Company Gas Sales Price Minus National Average Wellhead Price

Company	1988	1987	1986	1985	1984
Shell	+ .18	+ .18	+ .23	+ .23	+ .14
ARCO	- .03	- .04	0	+ .01	- .08
BP America	- .01	- .22	- .36	- .06	+ .01
Exxon	+ .09	+ .12	+ .07	+ .08	- .50
Chevron	- .31	- .32	- .25	- .33	- .31
Amoco	+ .16	+ .06	+ .05	+ .25	+ .27
Texaco	+ .01	- .12	- .08	- .29	- .44
Mobil	+ .18	+ .10	+ .02	- .12	- .23
Unocal	+ .10	- .04	0	- .30	- .37
USX	- .14	- .26	- .20	- .19	- .09
ORYX	- .12	- .18	- .13	- .04	- .16
Phillips	- .18	- .22	- .30	- .45	- .72
National Average Wellhead Price ($/Mcf)	1.71	1.67	1.94	2.51	2.66
(Companies with selling price above national average)	6	4	4	4	3

NOTE: National average wellhead prices are taken from "Monthly Energy Review," Energy Information Administration, March 1989.

Positive values mean the major oil producer price exceeded the natural average price; negative values mean the national average price exceeded the major oil producer's prices.

See note for Table 1.

Table 3
Revenues* from Sale of Oil (including Natural Gas Liquids)
and Natural Gas and Ratio of Oil and Gas Revenues
1984-1988
(Millions of dollars)

		1988			1987			1986			1985			1984		
Company	Rank	Oil	Gas	O/G Ratio	Oil	Gas	O/G Ratio	Oil	Gas	O/G Ratio	Oil	Gas	O/G Ratio	Oil	Gas	O/G Ratio
Shell	(1)	2,353	1.098	2.14	3,053	1.214	2.51	2,697	1.417	1.90	4,561	1,649	2.77	4,858	1.652	2.94
ARCO	(2)	2,409	979	2.46	3,359	887	3.79	2.159	1,048	2.06	4.436	1.343	3.30	4,583	1,352	3.39
BP America	(3)	3,203^e	190^e	16.9	3,801^e	152^e	25.0	2,130	142	15.00	4,888	179	27.31	4,363	152	28.70
Exxon	(4)	3,119	1,352	2.31	4,248	1,316	3.23	2,930	1,644	1.78	6,230	2,264	2.75	6,452	2,043	3.16
Chevron	(5)	2,204	1,036	2.13	2,744	956	2.87	2,344	1,215	1.93	5.303	1,670	3.18	4,770	1,692	2.82
Amoco	(6)	1,942	1.131	1.72	2,289	1,067	2.15	2,012	1,206	1.67	3,169	1,854	1.71	3,367	2.033	1.66
Texaco	(7)	2,442	1.342	1.82	2.923	1,159	2.52	2,928	1.365	2.15	5,457	1.945	2.81	5,311	2,096	2.53
Mobil	(8)	1,385	1,243	1.11	1,708	1,080	1.58	1,524	1,094	1.39	2,910	1,489	1.95	2,828	1,475	1.92
Unocal[1]	(9)	673	474	1.42	825	443	1.86	703	481	1.46	1,305	634	2.06	1,389	690	1.99
USX	(10)	755	490	1.54	934	386	2.42	854	538	1.59	1,640	767	2.14	1,743	824	2.11
ORYX	(11)	687	321	2.14	989	343	2.88	912	396	2.30	1,813	590	3.07	1,940	717	2.70
Phillips[1]	(12)	538	477	1.13	674	407	1.66	626	464	1.35	1,381	663	2.08	1,303	554	2.35
TOTALS		21,710	10,133	2.14	27,547	9,410	2.93	21,819	11,010	1.98	43,093	15,047	2.86	42,907	15,288	2.81

*Revenues computed by multiplying average weighted price by production.

^{e}Estimated product price, thus total revenue is estimated.

()Company rank with respect to oil and natural gas liquids reserves held.

[1] Excludes natural gas liquids from revenues.

Table 4
Natural Gas Reserves (U.S.), Production and Reserves to Production Ratio for Major Oil Reserve Holders
1983-1988
(Bcf)

Company	Rank	1988 Reserves	1988 Prod	1988 R/P	1987 Reserves	1987 Prod	1987 R/P	1986 Reserves	1986 Prod	1986 R/P	1985 Reserves	1985 Prod	1985 R/P	1984 Reserves	1984 Prod	1984 R/P	1983 Reserves	1983 Prod	1983 R/P
Shell	(6)	6,248	581	10.75	6.541	656	9.97	6,788	653	10.40	7,051	602	11.71	7,455	590	12.64	7,434	539	13.79
ARCO	(5)	6,373	583	10.93	5,854	534	10.96	5,923	527	11.24	6,134	533	11.51	5,988	524	11.43	5,765	481	11.99
BP America	(11)	2,273	112	20.29	1,932	105	18.40	1,832	90	20.36	1,751	73	23.99	1,512	57	26.53	779	55	14.16
Exxon	(2)	9.341	751	12.44	9,761	735	13.28	10,182	818	12.45	10,174	874	11.64	10,096	977	10.33	9,645	946	10.20
Chevron	(3)	8,274	740	11.18	7,078	708	10.00	7,509	719	10.44	7,752	766	10.12	8,280	720	11.50	4,877	422	11.56
Amoco	(1)	12,371	605	20.45	10,690	617	17.33	10,270	606	16.95	9.902	674	14.69	9,684	694	13.95	9,391	637	14.74
Texaco	(7)	4.665	780	5.98	4,783	748	6.39	5,132	734	6.99	5,803	876	6.62	6,539	944	6.93	5,481	674	8.13
Mobil	(4)	7.515	658	11.42	7,741	610	12.69	7,855	558	14.08	7,600	623	12.20	8,084	607	13.32	6,275	448	14.01
Unocal	(8)	4.320	276	15.65	4,399	283	15.54	4,500	255	17.65	4,728	297	15.92	4,824	325	14.84	5,049	301	16.77
USX	(10)	3.048	313	9.74	3,278	274	11.96	3,436	308	11.16	3,633	336	10.81	3,398	321	10.59	3,205	280	11.45
ORYX	(12)	2,239	202	11.08	2,232	230	9.70	2,377	219	10.85	2,588	239	10.83	2,728	287	9.51	2,931	271	10.82
Phillips	(9)	3,365	312	10.79	3,369	281	11.99	3,232	283	11.42	3,580	322	11.12	3,925	286	13.72	3,416	289	11.82
TOTALS		70,032	5,913	11.84	67,658	5,781	11.70	69,036	5,770	11.96	70,696	6,215	11.38	72,513	6,332	11.45	64,248	5,343	12.02
Percent of Total U.S.		41.7			41.6			41.[illegible]			41.9			41.9			36.6		

()Company rank reflects domestic natural gas reserves held and is valid only among these twelve companies. All companies hold more than 400 million barels of oil and natural gas liquids.

Table 5
U.S. Reserves of Oil and Natural Gas Liquids, Production and Reserves to Production Ratio for Major Oil Reserve Holders
1983-1988
(Millions of barrels)

		1988			1987			1986			1985			1984			1983		
Company	Rank	Reserves	Prod	R/P	Reserves	Prod	R/P	Reserves	Prod	R/P	Reserves	Prod	R/P	Reserves	Prod	R/P	Reserves	Prod	R/P
Shell	(1)	2,851	193	14.77	2,787	204	13.66	2,632	209	12.59	2,528	193	13.10	2,321	195	11.90	2,166	191	11.34
ARCO	(2)	2,829	246	11.50	2,818	243	11.60	2,728	240	11.37	2,746	237	11.59	2,746	240	11.44	2,573	238	10.81
BP America	(3)	2,678	314	8.53	2.953	309	9.56	2,817	291	9.68	3,014	285	10.58	3,270	242	13.51	3,187	230	13.86
Exxon	(4)	2,630	278	9.46	2,634	276	9.54	2,627	278	9.45	2,722	281	9.69	2,715	285	9.53	2,782	285	9.76
Chevron	(5)	1,806	178	10.15	1,809	185	9.78	1,880	199	9.45	2,088	214	9.76	1,328	115	11.55	1,182	116	10.19
Amoco	(6)	1.736	149	11.65	1,670	142	11.76	1,560	142	10.99	1,782	144	12.38	1,737	149	11.66	1,706	145•	11.77
Texaco	(7)	1,434	158	9.08	1,427	197	7.24	1,457	215	6.78	1,766	233	7.58	1,887	210	8.99	967	124	7.80
Mobil	(8)	1,140	111	10.27	1.024	112	9.14	1,014	114	8.89	1,036	120	8.63	1,040	113	9.20	855	115•	7.43
Unocal	(9)	639	64	9.98	656	63	10.41	671	63	10.65	666	65	10.25	663	65	10.20	662	64•	10.34
USX	(10)	596	56	10.64	621	58	10.71	628	64	9.81	629	68	9.25	608	65	9.35	605	65•	9.31
ORYX	(11)	594	47	12.64	621	59	10.53	649	62	10.47	699	71	9.85	745	71	10.49	655	74	8.85
Phillips	(12)	448	50	8.96	457	51	8.96	486	58	8.38	576	68	8.47	659	62	10.63	550	57	9.65
Totals		19,381	1,844	10.51	19,477	1,899	10.26	19,149	1,935	9.90	20,252	1,979	10.23	19,719	1,812	10.88	17,890	1,704	10.50
Percent of Total U.S.		55.3			55.0			54.6			55.7			54.6			50.2		

•Estimated.

()Company rank with respect to oil and natural gas liquids reserves held.

Table 6
Percent of Total U.S. Oil[2] and Natural Gas Reserve Ownership by 12 Large U.S. Oil Reserve Holders by Company

Company	1988 Natural Gas Reserves (Bcf)	Percent U.S. Total[1]	Rank	1988 Oil Reserves[2] (Million barrels)	Percent U.S. Total[1]	Rank
Shell	6,248	3.7	6	2,851	8.1	1
ARCO	6,373	3.8	5	2,829	8.1	2
BP America	2,273	1.4	11	2,678	7.6	3
Exxon	9,341	5.6	2	2,630	7.5	4
Chevron	8,274	4.9	3	1,806	5.2	5
Amoco	12,371	7.4	1	1,736	5.0	6
Texaco	4,665	2.8	7	1,434	4.1	7
Mobil	7,515	4.5	4	1,140	3.3	8
Unocal	4,320	2.6	8	639	1.8	9
USX	3,048	1.8	10	596	1.7	10
ORYX	2,239	1.3	12	594	1.7	11
Phillips	3,365	2.0	9	448	1.3	12
Average	5,836	3.5		1,615	4.6	

[1] Based on December 31, 1988, reported proved reserves by DOE/EIA, "U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves, 1988 Annual Report."

[2] Includes natural gas liquids.

Table 7

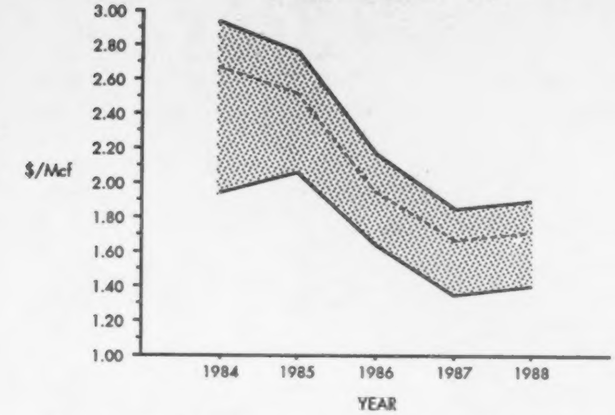
Summary of Interstate Pipeline Sales by Producers to Large Purchasers and Producing Areas

Producer	3 Largest Purchasers	Actual 6 Month Data	Percent of Total Interstate Pipe-Line Production	3 Largest Producing Areas	Percent of Total Interstate Pipe-Line Production	Composite Total Price ($/MMBtu
Shell	Florida Gas Trans.	Jul.-Dec. 87	30.4	Louisiana-Offshore	58.9	$2.04
	El Paso Nat. Gas	Jul.-Dec. 87	13.7	Texas-Permian	12.8	
	Transcontinental	Oct.87-Mar.88	13.6	Texas-Offshore	12.6	
Arco	Transcontinental	Oct.87-Mar.88	39.1	Texas-Offshore	35.3	$2.06
	Northern Nat. Gas	Mar.-Aug. 88	14.9	Louisiana-Offshore	34.3	
	Tenn. Gas Pipeline	Feb.-Jul.88	9.9	New Mexico	6.7	
BP America	N/A	N/A	N/A	N/A	N/A	N/A
Exxon	Columbia	Mar.-Aug.87	34.9	Louisiana-Offshore	51.3	$2.00
	Trunkline	Nov.87-Apr.88	18.4	Louisiana-South Onshore	15.7	
	Northern Nat. Gas	Mar.-Aug. 88	8.9	Texas-Permian	10.4	
Chevron	Texas Eastern	Apr.-Sept. 88	45.0	Louisiana-Offshore	62.5	$1.05
	Southern Natural	Jul.-Dec. 87	10.7	Rocky Mountain	9.6	
	Northern Nat. Gas	Mar.-Aug. 88	7.2	New Mexico	7.7	
Amoco	Williams	Aug.87-Jan.88	21.3	Louisiana-Offshore	21.1	$1.86
	Florida Gas Trans.	Jul.-Dec. 87	13.0	Kansas	21.0	
	El Paso Nat. Gas	Jul.-Dec. 87	9.5	Rocky Mountain	11.9	
Texaco	Tenn. Gas Pipeline	Feb.-Jul. 88	20.5	Louisiana-Offshore	31.5	$1.72
	El Paso Nat. Gas	Jul.-Dec. 87	13.8	New Mexico	12.5	
	Texas Gas Trans.	Mar.-Aug. 88	13.6	Texas-Offshore	11.5	
Mobil	Transcontinental	Oct.87-Mar.88	28.4	Louisiana-Offshore	35.9	$2.07
	Williams	Aug.87-Jan.88	12.7	Texas-Offshore	14.2	
	Trunkline	Nov.87-Apr.88	8.2	Kansas	9.4	
Unocal	Transcontinental	Oct.87-Mar.88	25.2	Louisiana-Offshore	60.7	$2.28
	Texas Gas Trans.	Mar.-Aug. 88	18.3	Louisiana-South Onshore	16.0	
	Tenn. Gas Pipeline	Feb.-Jul. 88	15.7	New Mexico	8.3	
USX	Texas Eastern	Apr.-Sept.88	51.3	Louisiana-Offshore	61.9	$2.04
	Colorado Interstate	Dec.87-May 88	9.5	Rocky Mountain	15.9	
	Natural Gas Pipeline	May-Oct. 88	8.5	New Mexico	10.4	
ORYX	Texas Eastern	Apr.-Sept. 88	24.5	Louisiana-Offshore	39.4	$1.95
	Trunkline	Nov.87-Apr.88	15.9	New Mexico	15.4	
	Transcontinental	Oct.87-Mar.88	14.5	Texas-Gulf Coast (District 4)	9.5	
Phillips	El Paso Nat. Gas	Jul.-Dec. 87	19.3	Louisiana-Offshore	36.0	$1.73
	Panhandle Eastern	May-Oct. 88	17.5	Texas-Permian	19.0	
	Texas Eastern	Apr.-Sept. 88	12.9	Rocky Mountain	13.7	

SOURCE: Foster Bulletin on Deregulated Gas. Foster Associates. Producer Supplement - January 1989.

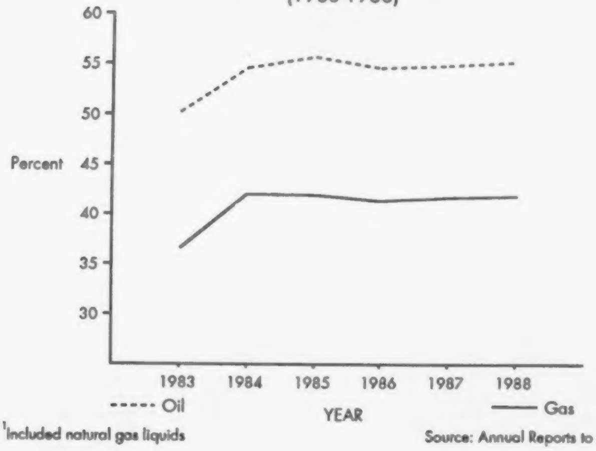
NOTE: This table enumerates interstate pipeline sales data only. Additionally, the table is not representative of total annual sales data, but is instead a "snap-shot" of interstate pipeline sales at the dates noted.

FIGURE 1
Range of Natural Gas Wellhead Prices 12 Companies (1984-1988)



Sources: Annual Reports to Stockholders
(See Table 1) Monthly Energy Review, March 1989,
Energy Information Administration

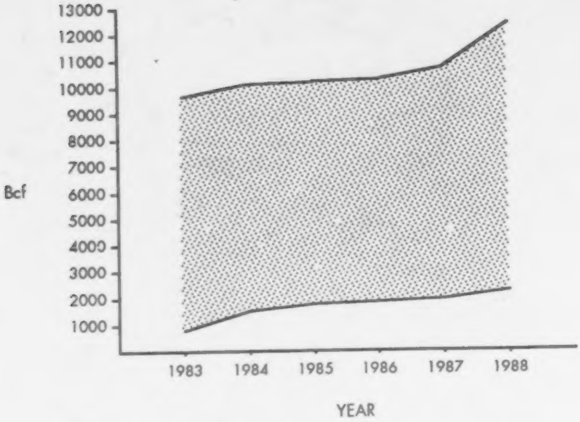
FIGURE 2
Percentage of Total U.S. Oil[1] and Natural Gas Reserve Ownership by 12 U.S. Oil Reserve Holders in Aggregrate (1983-1988)



[1] Included natural gas liquids

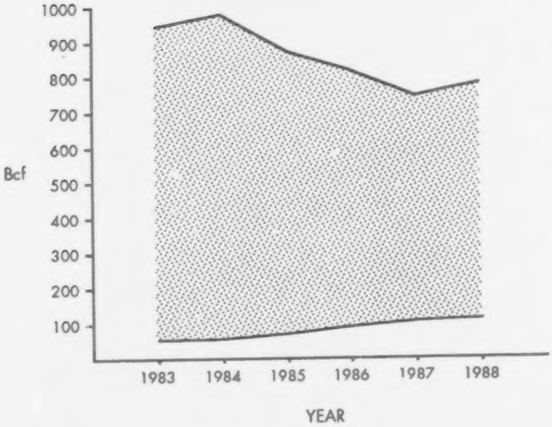
Source: Annual Reports to stockholders

FIGURE 3
Range of Natural Gas Reserves
12 Companies (1983-1988)



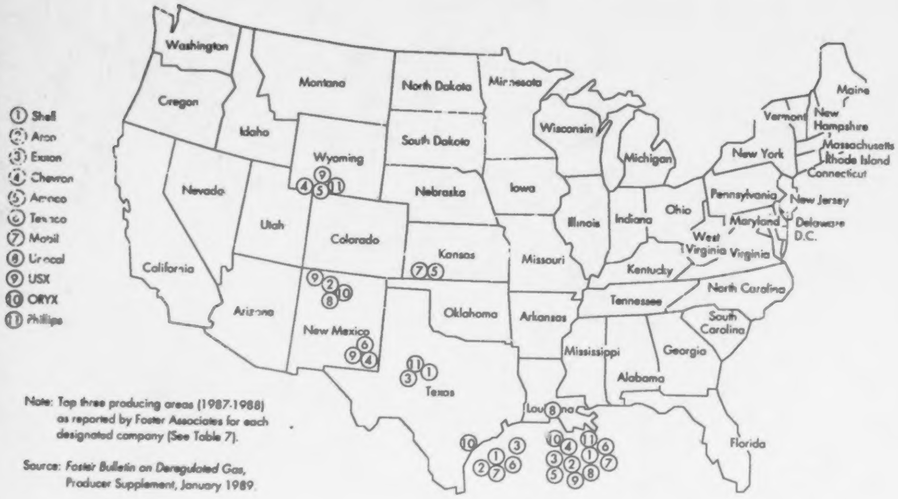
Source: Annual Reports to Stockholders (see Table 4)

FIGURE 4
Range of Natural Gas Production
12 Companies (198301988)



Source: Annual Reports to Stockholders (see Table 4)

FIGURE 5
Predominate Gas Field Sales by Producing Area


① Shell
② Arco
③ Exxon
④ Chevron
⑤ Amoco
⑥ Texaco
⑦ Mobil
⑧ Unocal
⑨ USX
⑩ ORYX
⑪ Phillips
Washington
Oregon
California
Nevada
Idaho
Montana
Wyoming
Utah
Arizona
Colorado
New Mexico
North Dakota
South Dakota
Nebraska
Kansas
Oklahoma
Texas
Minnesota
Iowa
Missouri
Arkansas
Louisiana
Wisconsin
Illinois
Michigan
Indiana
Ohio
Kentucky
Tennessee
Mississippi
Alabama
Georgia
Florida
South Carolina
North Carolina
Virginia
West Virginia
Maryland
Delaware
D.C.
Pennsylvania
New Jersey
New York
Vermont
New Hampshire
Maine
Massachusetts
Rhode Island
Connecticut
⑨ ④ ⑤ ⑪
⑨ ② ⑩ ⑧
⑦ ⑤
⑥ ⑨ ④
⑪ ③ ①
⑩ ① ③ ② ⑦ ⑥
⑧
⑩ ④ ⑪ ⑥ ③ ② ① ⑦ ⑤ ⑨ ⑧

Note: Top three producing areas (1987-1988) as reported by Foster Associates for each designated company (See Table 7).

Source: *Foster Bulletin on Deregulated Gas*, Producer Supplement, January 1989.

Appendix A

Mergers and Acquisitions Among the Twelve Top Liquids Reserves Holders (1988)

Current Corporate Title	Rank[1]	Major Acquisitions	Decade of Acquisition	Antecedent Oil Company
Shell	1	--	--	Royal Dutch Shell
Arco[2]	2	Richfield	1960s	Atlantic
		Sinclair	1960s	
BP America	3	--	--	Standard Oil (Ohio)/British Petroleum
Exxon	4	--	--	Standard Oil (NJ)
Chevron[2]	5	Standard Oil (Kentucky)	1960s	Standard Oil (California)
		Gulf	1980s	
Amoco[2]	6	--	--	Standard Oil (Indiana)
Texaco	7	Getty	1980s	The Texas Company
Mobil	8	Superior	1980s	Socony Vaccuum
Unocal	9	Pure	1960s	Union Oil
USX	10	Plymouth Oil	1960s	Ohio Oil
		Marathon	1970s	
		TXO	1970s	
ORYX	11	Sunray	1960s	SUN
Phillips	12	Aminoil	1980s	Phillips
		General America	1980s	

[1] Based on total domestic oil and natural gas liquids held.

[2] Purchased significant reserves and properties from Tenneco, Inc. during 1988 sale of Tenneco Oil Company exploration and production assets.

AGA American Gas Association

Planning & Analysis
Issues

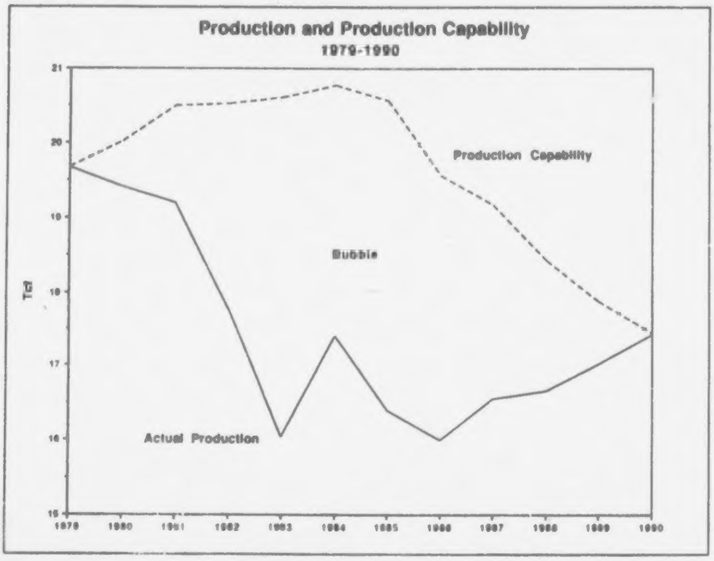
Issue Brief 1989-12 July 25, 1989

Natural Gas Production Capability - 1989-1990

In Brief

The excess natural gas production capability (the gas "bubble") that has characterized the natural gas market since 1980 is expected to be gone by 1990 (see Figure 1). By the end of 1989, annualized gas supplies and requirements on a national average basis will be in approximate balance. A similar supply/demand balance is projected for 1990.

Figure 1



NOTE: Throughout this study, gas volumes (i.e., Tcf, Bcf, etc.) are used in lieu of energy values in Btu (i.e., quadrillion Btu or trillion Btu). The conversion factor employed is taken from the EIA Monthly Energy Review of March 1989. This conversion factor is 1,031 Btu per cubic foot of natural gas.

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This annualized bubble estimate does not consider seasonal deliverability constraints, and therefore, a monthly regional deliverability study has been added to this analysis to judge the reasonableness of estimated declines in production and production capability. Part of the evaluation of the bubble is based on 1980 production compared to recently demonstrated peak production levels. When these seasonal production capabilities are considered, the results show little slack in the system during periods of peak winter demand. Given the lack of excess capability during peak periods, some interruptions of interruptible and "best efforts" customers are likely during peak requirements periods. These occurrences should not be misinterpreted as a "gas shortage;" but rather, how the industry will operate in the new competitive environment. Therefore, the end of the "annualized" gas bubble could result in less reliable gas service to customers who choose the lowest cost/least reliable option from their supplier.

Two factors caused the bubble to decline since the mid-1980s: (1) declining domestic production capability due to reduced drilling (the result of low energy prices and shut-in gas production); and (2) higher gas demand due primarily to lower natural gas prices. By 1990, the bubble will have shrunk enough to spur drilling activity that will, some time after 1990, reverse the decline in production capability. This analysis assumes that takes of Canadian gas supplies will be about 1.3 Tcf in the 1989 and 1990 periods. These imports have the net effect of slowing the decline of the bubble. The availability of liquefied natural gas (LNG) in the winter of 1989/1990 could also help offset deliverability constraints associated with peak seasonal requirements.

Introduction

This analysis estimates the unused production capability for each year from 1980 through 1990 using the most recent statistics available. This assessment of the domestic unused production capability updates the earlier work and takes into account the variations in domestic production (due to lack of requirements) since 1979. Estimates for unused production capability in 1989 are based on generally increasing gas requirements and production trends from 1986 to 1990.

This analysis does not include in its "bubble" estimates either the large amounts of gas that are not connected to the pipeline system (and thus not presently available to markets) or contracted for but untaken Canadian gas supplies. If gas demand were to grow more rapidly than anticipated in this issue paper, these additional sources of gas could be quickly brought to the market. An earlier study, A.G.A. Energy Analysis 1986-12, examines these and other potential short-term supplies.

Reduced consumption of natural gas from the 1975-81 average of 19.7 Tcf per year, coupled with nearly constant domestic gas delivery capability from 1980-1986, led to the "gas bubble." Several past analyses have evaluated the size of this "bubble." In this study the estimate of the "bubble" size is updated -- that estimate reflects both demand growth and a low level of drilling -- causing the continued decline in the size of the bubble.

Natural gas production was 19,663 Bcf in 1979 and declined significantly in the 1980s to a low point of 15,991 Bcf in 1986. An annual production level of 17.0 Tcf or more is anticipated for 1989 and 1990. By 1990, the levels of gas requirements will equal the sum of Canadian imports, supplemental gas supplies and domestic gas production. Economic conditions, the pricing practices of competitive energy sources, particularly oil products, weather and conservation each play a part in establishing the level of gas requirements.

Methodology

The methodology used in this analysis is based on the extrapolation of individual gas well production trends. With this technique, total U.S. non-associated gas production and the number of producing gas wells in a given year are used to calculate an average production volume per gas well. This value is compared to the estimate of gas well production capability, which is the result of extrapolation of 1977-1979 production trends that show a decline in production per gas well of about 5 percent per year. This period was chosen because it reflects production per well statistics when there was no significant unused production capability. (The 1980-1988 data reflect a period when the actual declines in production per gas well were caused in part by reduced demand.)

An estimate of domestic production capability was developed based on total wells drilled, gas well completions and gas wells abandoned. Producing gas well estimates for 1988-1990 were based on low rig counts (under 1,000 in 1989 increasing steadily to as much as 1,400 in 1990) and typical historic abandonment rates (3,000-4,400 wells per year). The gradual increase in producing gas wells is compatible with gas well completion estimates of almost 7,500 in 1988, steadily increasing to 10,000 by 1990.

The production capability per well, when multiplied by the number of producing wells, yields an estimate of total non-associated gas production capability between 1979-90. Estimates of associated-dissolved gas production (from oil wells) are based on recent production data as reported by EIA and are projected on the basis of the percentages of total production that is associated-dissolved gas. These data are adjusted from reported EIA statistics because EIA reports natural gas volumes wet (i.e., including liquids). In this study, the sum of the non-associated gas production and the associated-dissolved production is made equal to the total dry production as reported by EIA for years through 1988. After 1988, projections of production capability are estimated as the sum of non-associated gas production capability and the implied forecast of associated-dissolved production.

Table 1
PRODUCTION PER GAS WELL

Year	Total Gas Production in Bcf	Non-Associated Gas Production in Bcf[1]	Ratio of Non-Associated Gas Produced to Total Gas Production[2]	Producing Gas Wells	Annual Non-Associated Gas Production per Gas Well MMcf
1975	19,236	15,389	.800	130,364	118.0
1976	19,098	15,259	.799	137,542	110.9
1977	19,163	15,560	.812	147,658	105.4
1978	19,122	15,737	.823	157,454	99.9
1979	19,663	16,320	.830	169,891	96.1
1980	19,403	16,007	.825	182,004	87.9
1981	19,181	15,920	.830	198,839	80.1
1982	17,758	14,597	.822	210,753	69.3
1983	16,033	12,794	.798	221,952	57.6
1984	17,392	14,001	.805	233,853	59.9
1985	16,382	13,007	.794	243,344	53.5
1986	15,991	12,633	.790	241,527	52.3
1987	16,536	13,262	.802	249,225	53.2
1988	16,642	13,480	.810	252,000[4]	53.5
1989	17,000[3]	13,855	.815	256,000[4]	54.1
1990	17,400[3]	14,181	.815	260,000[4]	54.5

---

[1] Based on the total gas production estimates as shown in Column Two.

[2] The ratio of non-associated gas production has generally declined during the period of low demand. With the bubble declining and less gas well production shut-in, the ratio should return to previously established levels.

[3] Based on estimates provided in Appendix I.

[4] Based on assumptions regarding the number of gas wells completed and abandoned each year. Because of the poor market conditions, the number of producing gas wells is estimated to increase by less than 3,000 wells in 1988. Thereafter, the annual change in producing gas wells is estimated to rise so that the annual increase is 4,000 wells in 1989 and 1990.

Sources: A.G.A. Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada as of December 31, 1979; EIA, Monthly Energy Review; EIA, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves; EIA, Natural Gas Annual 1987, Volume 1.

NOTE: Throughout the production section of this study, gas volumes (i.e., Tcf, Bcf, etc.) are used in lieu of energy values in Btu (i.e., quadrillion Btu or trillion Btu). The conversion factor employed is taken from the EIA Monthly Energy Review of March 1989. This conversion factor is 1,031 Btu per cubic foot of natural gas.

Table 1 provides the statistical data necessary to develop historical estimates of non-associated gas production per well through 1986. Estimates of production in the 1988-1990 period are based on available EIA statistical data through February 1989 and independent evaluations of imports and other supplemental gas supplies as shown in Appendix I.

The historical non-associated gas production in Table 1 has been derived from the EIA annual reserves reports and the EIA Monthly Energy Review. The reserves reports are used to obtain ratios of non-associated gas production to total gas production. Producing gas well data are taken from published Natural Gas Annual 1987 statistics.

Table 2 shows estimates of the non-associated gas production capability per well, the number of producing gas wells, the non-associated production capability and the associated-dissolved gas production. The difference between the capability to produce and actual production is the basis of the calculation of the unused production capability as shown in Table 3.

Maximum Production Capability

The estimates developed here are intended to evaluate what production levels might be achieved with wells already drilled and attached to pipelines. Some additional capacity also exists in wells that are capable of gas production but have not been completed or are not connected to a pipeline. In addition, there are large volumes of gas behind the pipe[2] (gas not being produced because production from that well is presently coming from other depths) that are excluded from production capability. In both situations, these volumes of gas represent currently unavailable sources of gas capability that are not utilized.

These estimates include only gas that comes from reservoirs currently capable of producing and connected to pipelines. A larger volume could be produced under different operating conditions.

Annualized Results

This methodology shows that the unused production capability increased significantly in the early 1980s. (See Table 3 below.) The unused capability rose rapidly to a peak level in 1983 of 4.6 Tcf and then started to decline. This decline was somewhat uneven given the sharp drop in domestic requirements in 1985 and 1986. The decline in unused production capability is primarily due to reduced drilling activity coupled with increased demand. The declining production per gas well since 1979 was counterbalanced by the increasing number of producing gas wells through 1984 and, as a result, these factors were in equilibrium and production capability remained nearly constant at just over 20 Tcf. The decline in drilling (resulting from the low rig count levels) reduced the rate of growth in the number of producing gas wells in 1985. The decline in production per gas well will become a major factor in the 1988-1990 time period so that the total productive capacity declines from 20,558 Bcf in 1985 to a low level of about 17,400 Bcf in 1990. This in turn contributes to a decline in the "bubble size" from the 4.2 Tcf of 1985 to essentially zero in 1990.

Table 2

ESTIMATES OF PRODUCTION CAPABILITY 1979-1990

Year	Non-Associated Production Capability per Gas Well[1]	Number of Producing Gas Wells	Non-Associated Production Capability in Bcf	Associated-Dissolved Production in Bcf[2]
1979	96.06 MMCF	169.891	16.320	3.343
1980	91.26 MMCF	182.004	16.610	3.396
1981	86.69 MMCF	198.839	17.237	3.261
1982	82.36 MMCF	210.753	17.358	3.161
1983	78.24 MMCF	221.952	17.366	3.239
1984	74.33 MMCF	233.853	17.382	3.391
1985	70.61 MMCF	243.344	17.183	3.375
1986	67.08 MMCF	241.527	16.201	3.358
1987	63.73 MMCF	249.225	15.883	3.274
1988	60.54 MMCF	252.000	15.256	3.162
1989	57.51 MMCF	256.000	14.723	3.145
1990	54.64 MMCF	260.000	14.206	3.219

[1] The 1980-1990 estimates are based on a 5 percent per year decline from the production capability demonstrated in 1979 (when there was little or no unused production).

[2] These values are the implied associated-dissolved production based on date in Table 1.

NOTE: Throughout the production section of this study, gas volumes (i.e., Tcf, Bcf, etc.) are used in lieu of energy values in Btu (i.e., quadrillion Btu or trillion Btu). The conversion factor employed is taken from the EIA Monthly Energy Review of March 1989. This conversion factor is 1.031 Btu per cubic foot of natural gas.

Drilling Implications

The implications of these results in regard to drilling more gas wells are critical. In 1989, the difficulty of selling new production into the over-supplied market as well as a soft, volatile spot market still existed. As a result, the major oil companies and independent producers did not significantly increase their exploration and production budgets.

By 1990, drilling activity is projected to increase some, no longer severely affected by the "bubble." The projected "bubble" will be essentially zero and will not be a major deterrent to the development of new gas resources. By 1990, the disappearance of the "bubble" will allow production to be more easily marketed and, as a result, a resurgence in gas well drilling may be anticipated.

Table 3

PRODUCTION AND PRODUCTION CAPABILITY[1]
1979-1990
(in Bcf)

Year	Actual Production[2,3]	Production Capability[4]	Unused Production Capability
1979	19,663	19,663	0
1980	19,403	20,006	603
1981	19,181	20,498	1,317
1982	17,758	20,519	2,761
1983	16,033	20,605	4,572
1984	17,392	20,773	3,381
1985	16,382	20,558	4,176
1986	15,991	19,560	3,569
1987	16,536	19,157	2,621
1988	16,642	18,418	1,776
1989	17,000	17,868	868
1990	17,400	17,425	Neg.

[1] Expanded from non-associated production capability using extrapolations of ratios established in Table 1 sources.

[2] EIA Monthly Energy Review, March 1989. Data for 1989-1990 are based on estimates detailed in Appendix I.

[3] Production in 1989 and later years based on assumptions concerning domestic requirements and supplemental sources such as Canadian imports.

[4] This estimate is the sum of the non-associated production capability and the associated-dissolved production from Table 2.

NOTE: This methodology assumes that prior to 1980 there was no unused production capability.

Throughout the production section of this study, gas volumes (i.e., Tcf, Bcf, etc.) are used in lieu of energy values in Btu (i.e., quadrillion Btu or trillion Btu). The conversion factor employed is taken from the EIA Monthly Energy Review of March 1989. This conversion factor is 1,031 Btu per cubic foot of natural gas.

Sensitivity of Results.

The results of this analysis through 1988 are generally consistent with the earlier analyses reported in the Gas Energy Review ("1985 Outlook", "1986 Outlook", July 1986, "1987 Outlook", July 1987, "1988 Outlook", July 1988, January 1989). "Bubble" estimates for the future are, of course, extremely sensitive to the assumed levels of 1989-1990 consumption. In this study, A.G.A. has assumed consumption levels generally consistent with A.G.A.'s Total Energy Resource Analysis (TERA) Base Case model and other recent A.G.A. publications.

Monthly National Production Capability.

The methodology outlined above indicates that the projected total production capability through 1986 has decreased only slightly since 1979. Decreasing production per gas well has been generally offset by the increase in the number of producing gas wells. This finding is controversial because claims have been made of major losses in national production capability.[3] These two points of view can be examined by looking at what production has actually been in recent years as shown in Table 4.

Table 4 is a tabulation of the daily production rates for the month of maximum production for six major gas producing states and the total United States. The final five columns of the table show the ratios of the production in each state for 1985, 1986, 1987, 1988 and the first two months of 1989, compared with 1980. The general conclusion is that while production levels are typically lower in the later years, the capacity to produce gas nationally has been demonstrated at 88-90 percent of the 1980 level. At worst, a decline of ten to twelve percent might be indicated. At best, there has been no loss in production capability at all.

In 1984, many Texas wells experienced damage due to freezing weather that severely limited production at that time. Subsequently, there has been extensive speculation that the Texas gas production capability could be significantly lower than it was in 1980.[3] Table 4 statistics on Texas production indicate that as recently as February 1989, the Texas production level was demonstrated at 87.2 percent of the maximum production level achieved in any year since 1980.

Annualized Short Term Gas Supplies

This study does not reflect the full deliverability from other gas supplies. The alternative sources of gas are discussed in Energy Analysis 86-12, titled "Short-Term Gas Supply Potential." These sources include gas from uncommitted non-producing gas reserves, additional Canadian gas, accelerated infill drilling, Mexican gas and imports of liquefied natural gas. Energy Analysis 86-12 demonstrates a potential to bring an additional 1,150 Bcf within twelve months and as much as 2,450 Bcf by 1990 if needed. Some of this capability is already in use (especially Canadian gas), and some is expected shortly (LNG).

Supply-Demand Balance

The emerging natural gas market is highly price sensitive and competitive. Today, gas production clears the market by the mechanism of price adjustments in the spot market. As a result, major swings in spot market prices have been observed. These price variations have so far been more characteristic of selling the available gas rather than customers bidding for limited gas supplies. However, during future winter heating seasons,

Table 4

DEMONSTRATED NATURAL GAS PRODUCTION IN PEAK MONTHS

State	Daily Production Demonstrated in Peak Month*										Ratios				
	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989[1]	1985/1980	1986/1980	1987/1980	1988/1980	1989/1980[1]
Kansas	3,270	2,188	2,191	2,057	1,967	2,194	1,903	1,929	1,948	1,607	.671	.582	.590	.596	.491
Louisiana	20,446	19,686	18,709	15,928	18,535	16,537	15,814	15,112	15,088	15,117	.809	.773	.739	.738	.739
New Mexico	3,339	3,339	3,307	2,972	3,061	3,148	2,420	2,804	2,727	2,551	.943	.725	.840	.817	.764
Oklahoma	6,444	6,252	6,611	5,608	6,182	6,246	5,846	5,932	5,698	5,964	.969	.907	.921	.884	.926
Texas	20,143	19,511	19,013	17,483	18,482	18,284	18,036	18,382	18,309	17,573	.908	.895	.913	.909	.872
Wyoming	1,308	1,345	1,378	1,509	1,588	1,356	1,502	1,690	1,981	2,247	1.037	1.148	1.292	1.515	1.718
U.S.	59,061	55,974	55,749	51,763	55,881	53,054	52,077	51,862	51,909	52,201	.898	.882	.878	.879	.884

*in MMcf

1. January-February only.

Source: EIA, Natural Gas Monthly, April 1989.

NOTE: Throughout this study, gas volumes (i.e., Tcf, Bcf, etc.) are used in lieu of energy values in Btu (i.e., quadrillion Btu or trillion Btu). The conversion factor employed is taken from the EIA Monthly Energy Review of March 1989. This conversion factor is 1,031 Btu per cubic foot of natural gas.

significant spot market price volatility should be expected.[4] The ability of price variations to allocate gas supplies so as to permit high priority customers who require service to gain access to adequate supplies has not been demonstrated in a severely cold winter. Nevertheless, these price fluctuations are likely to cause interruptible and dual-fuel capable customers to switch to less expensive fuels when severe weather causes sharp increases in gas demand. As a result, a relatively long period of supply-demand balance is considered possible over the next few years. Price volatility, with the resulting loss of dual-fuel customers to oil over peak periods occurred on a limited scale during the 1988/89 winter.

Conclusions

Natural gas production in early 1989 was again limited by the demand for natural gas. Estimates of production capability are highly susceptible to error; however, an annual unused production capability of about 850 Bcf probably exists in 1989. This level will decrease to close to zero during the winter of 1989-90. The current less-regulated gas market should be able to operate successfully with such a nearly balanced supply and demand picture. However, one should anticipate price volatility to be a key element in the seasonal allocation of gas supplies.

Footnotes

[1] A.G.A. estimates of the "bubble" are lower than the EIA evaluations (see EIA Natural Gas Monthly Table, titled "Estimated Surplus Natural Gas"), which include Canadian gas and may also involve some double counting. This is especially true if a comparison of twelve-month periods is made.

[2] "Behind the pipe" reserves are gas volumes that are known to exist in producing reservoirs but are at depths other than the zones currently being produced (usually shallower depths). When the strata that are being produced have been depleted, the well will be sealed at those production levels and production of the "behind the pipe" reserves will commence.

[3] Natural Gas Deliverability Study - Final Report, Interstate Oil Compact Commission, December 1984.

[4] Natural Gas - Next Winter, A Report of the A.G.A. Gas Supply Committee, November 1988.

APPENDIX I

Table 1

Gas Demand and Production 1989-1990 (in Tcf)

Year	Requirements[1]	Supplemental Gaseous Fuels[2]	Domestic Production
1989	18.4	1.4	17.0
1990	18.8	1.4	17.4

[1] Estimates are consistent with the A.G.A. 1989 Gas Consumption Forecast and the current A.G.A.-TERA Base Case published in January 1989. The "requirements" volumes include "unaccounted for" gas. The consumption estimates are often made in quadrillion Btu, whereas this table lists values in trillions of cubic feet.

[2] Includes Canadian imports, SNG from liquid hydrocarbons, coal gasification, LNG, etc.

Table 2

Wells Drilled and Rig Count 1973-1988

Year	Gas Well Completions[1]	Total Wells Drilled[1]	Rig Count[2]
1973	6.98	27.69	1,194
1974	7.17	33.04	1,472
1975	8.17	38.89	1,660
1976	9.44	40.94	1,658
1977	12.12	45.86	2,001
1978	14.41	50.06	2,259
1979	15.17	51.91	2,177
1980	17.22	69.84	2,909
1981	19.91	90.03	3,970
1982	18.73	83.43	3,105
1983	14.28	74.90	2,232
1984	16.79	84.35	2,428
1985	14.10	69.18	1,980
1986	7.89	38.34	964
1987	7.49	34.22	936
1988	7.37	29.44	936
1989	-	-	778[3]

1. In thousands of wells.
2. Weekly average.
3. First five months of 1989.

SOURCE: EIA, Monthly Energy Review, March 1989.

NOTE: Throughout this study, gas volumes (i.e., Tcf, Bcf, etc.) are used in lieu of energy values in Btu (i.e., quadrillion Btu or trillion Btu). The conversion factor employed is taken from the EIA Monthly Energy Review of March 1989. This conversion factor is 1,031 Btu per cubic foot of natural gas.

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SHORT-TERM GAS SUPPLY POTENTIAL - 1989 UPDATE

Digest

A problem facing our industry today is the continuing uncertainty about gas supply. This uncertainty is increasing because we are emerging from an extended period of a gas surplus with attendent low levels of drilling activity.

An examination of future gas supplies can be divided into three periods: (1) the immediate surplus deliverability; (2) the transition from this surplus deliverability to supply/demand equilibrium; and (3) the long-term. This paper focuses on one aspect of item 2. A.G.A. Issue Brief 89-12 deals with item 1. The transitional period from surplus deliverability to supply/demand equilibrium in the early 1990s is an area of increasing interest. In this paper a number of auxiliary sources of supply, which can be brought on-line quickly to ease any sudden supply irregularities, are discussed. The paper stresses the liklihood of a balance of supply and demand in contrast to forecasts of an unstable system that operates out of control -- shortage to surplus to shortage. A similar analysis was performed in 1986.

The volume of gas supplies available in the short term from each of the sources outlined in this paper depends on the lead times to develop the supplies. In 12 months, from 0.7 to 1.4 Tcf more gas could be available each year from sources such as nonproducing reserves, Canadian imports, accelerated infill drilling and LNG imports. With a 36-month lead time, from 1.3 Tcf to 2.1 Tcf of incremental annual gas production could be available. These marginal gas supplies would come from these sources (both existing and new projects) so that if the bubble ends in 1990 (as expected), additional supplies of as much as 2.1 Tcf/yr. could be developed by 1993. This capability should provide confidence that a sudden surge in demand could not cause supply shortages.

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SHORT-TERM GAS SUPPLY POTENTIAL - 1989 UPDATE

A. Introduction

Recently there has been extensive speculation on the possibility of a gas supply shortage in the 1990s because of the drilling slump of the second half of the 1980s. The rationale for shortage projections is that: (1) gas exploration and production activity will be unable to respond quickly after this period of sharply reduced drilling; and (2) crude oil and natural gas prices will remain depressed even as gas supplies get tight -- thus dampening drilling activity even as gas requirements exceed production.

The rationale against shortages is based on extensive dual fuel capability in the gas requirements, the growing role of gas storage and the availability of several incremental gas supply sources that can be quickly brought to market. The purpose of this analysis is to identify and quantify these gas supply sources that could be brought to market quickly as the "gas bubble" disappears.

A.G.A. previously forecast that excess domestic production capability (gas bubble) will decline to about 850 Bcf in 1989 and will be gone by 1990. A.G.A. estimated that the domestic gas bubble peaked at 4.6 Tcf in 1983 and has been steadily decreasing in size since 1985. The long-awaited demise of the bubble has been a result of both increases in gas demand (since 1986) and decreased domestic gas production capability (since 1984). The balance between supply and demand in the short term depends on: (1) the availability of additional gas supplies that can enter the market quickly; (2) a market allocation process that determines which end-users are served during periods of maximum demand. The latter need is satisfied by a large spot market that allows bidding for gas supply on a monthly basis. The supply-side requirement is the subject of this paper.

B. Executive Summary

This analysis identifies four important gas supply categories that could be brought into production quickly (generally less than 12 months assuming full regulatory support) and significantly increase the nation's gas supply (see Table 6 at the end of this analysis).

- Nonproducing Reserves. There are significant gas reserves in reservoirs in the lower-48 states that are not producing gas and are shut in. EIA estimated the nonproducing gas reserves at 29.2 Tcf at year-end 1987. Much of this gas could be brought to the market quickly (less than a year), with an annual deliverability of 0.25-0.75 Tcf or within three years, 0.5-1.0 Tcf. This gas has been specifically excluded from the A.G.A. calculation of the size of the gas bubble.

- Canadian Gas. U.S. companies currently have contracts with Canadian pipelines and producers to import up to 1.5 Tcf/yr. which is about the current pipeline capability. However, when seasonal, marketing and physical deliverability constraints are considered, this capability is closer to 1.4 Tcf/yr. It is estimated that 1.8 Tcf/yr. of Canadian gas could be imported into the U.S. with additional pipeline construction. Most of this needed construction has already been proposed to the national regulatory bodies. Given that 1988 Canadian imports totaled about 1283 Bcf, 400 to 500 Bcf/yr. of additional gas could be made available to U.S. purchasers. Construction of pending major pipeline projects could increase this total deliverability to 1.9 Tcf/yr. and by 2000 this total deliverability would reach 2.0 Tcf/yr. Thus 120 Bcf of additional Canadian gas is available immediately, with 400 Bcf available by the early 1990s and 0.7 Tcf/yr. above the 1988 import level, by 2000.

- Accelerated Infill Drilling. In the early 1980s gas deliverability increased as a result of extensive infill drilling into known gas fields. Several of the largest gas fields in the country remain amenable to infill drilling to increase production capability and proved reserves. Infill drilling proposals by producers in the Hugoton basin have cited reserve increases as high as 7.6 Tcf -- similar accelerated drilling proposals in the San Juan basin could add 1.4 Tcf of reserves. Nationwide such accelerated infill drilling could increase production capability by 0.1-0.4 Tcf/yr. in three years and 0.05 to 0.1 Tcf/yr. within the next 12 months.

    - The major constraints to infill drilling are: (1) a lack of gas demand; (2) low gas prices, and (3) state spacing regulations. The latter impediment is being lifted in a number of states while the former constraint will be gone in 1990 when the bubble disappears.

    - Given that gas from this source requires new drilling (typically low-cost drilling), the quantity and timing of this supply source is impacted by relative gas prices.

- LNG. There are four LNG terminals that have been operational and could become operational again. Collectively, these terminals have the capacity to handle about 850 Bcf per year. Competitive pricing for LNG imports depends on the willingness of the producing country to accept a net-back price that will provide gas that is competitive at the burner tip. Each nation has its own level of acceptable wellhead prices, which varies greatly with the current economic conditions. Nevertheless, in the event that additional gas supplies were needed in the U.S., 50 Bcf could be anticipated from

LNG within 12 months, and up to 200 Bcf/yr. by the early 1990s and 850 Bcf by the mid-1990s.

- Overall, there exists a short-term (12 to 36 month) gas supply response potential of between 0.7 Tcf/yr. and 2.1 Tcf/yr. that could come on line if needed. These additional supplies should prevent a shortage from occurring and act as a bridge source of natural gas during the time it takes the exploration and production industry to explore for and develop new longer-term supply sources.

C. Nonproducing Reserves

The Energy Information Administration annually reports the volume of proved reserves in nonproducing reservoirs as of December 31.[1] The lower-48 state statistics for nonproducing reservoirs are listed in Table 1. In the lower-48 states, about 29.2 Tcf (dry) of natural gas was in nonproducing reservoirs at year-end 1987. This gas is being held out of the market for many reasons, e.g., non-availability of production equipment, gathering lines, transportation facilities, processing capacity, etc. At year-end 1987 about 49 percent of the nonproducing reserves were offshore. These offshore reserves, when connected to the appropriate gathering and processing facilities, are generally capable of production at a higher rate (lower reserves to production ratio) than the national average.

The dramatic increase in nonproducing natural gas reserves started in 1983 and by 1985 had risen 35 percent over the 1982 levels. This rise is closely correlated in time to the increase in the bubble size.[2] As the bubble has increased, the volume of nonproducing reserves has increased. Table 1 develops a methodology that assumes that an increased level of production, between 750 and 2500 Bcf could be achieved from this excess volume of nonproducing reserves.

Nonproducing reserves are subject to a wide range of impediments that prevent immediate production. Some of these reserves require only small gathering system extensions to be built, some offshore reserves require that production platforms be built or completed, etc. Therefore, the average rate of production for these reserves is variable. The possible production from these nonproducing reservoirs is calculated in Table 1 by developing an average volume of nonproducing reserves for the years from 1977 through 1981. This volume, 23,175 Bcf, is typical of the normal amount of reserves that were in nonproducing reservoirs prior to the impact of the bubble on the market. Subsequently, the bubble caused a slowing of the development of gas reserves and significant increases in gas volumes in nonproducing reservoirs. This is apparent in Table 1 for the years after 1982. Nonproducing volumes increased 1,071 Bcf (dry) from 1982 to 1983 and continued increasing to over 30 Tcf in 1985 and 1986.

Table 1
Lower-48 Proved Reserves of Natural Gas In Nonproducing Reservoirs
(in Bcf)

Year	Reserves	Nonproducing Reserves[1]	Reserve Life Index[2]	Average Reserves In Nonproducing Reserves 1977-81	Production Potential[3]	Actual Production[4]	Possible Increase In Production[5]
1977	175,170	25,228	8.05	23,175	-	-	-
1978	175,988	23,947	8.18	23,175	-	-	-
1979	168,738	21,248	7.75	23,175	-	-	-
1980	165,639	22,745	7.73	23,175	-	-	-
1981	168,693	22,708	7.89	23,175	-	-	-
1982	166,522	22,383	8.36	23,175	18,099	17,245	854
1983	165,964	23,454	9.19	23,175	18,029	15,515	2,514
1984	162,987	24,842	8.19	23,175	17,653	16,869	784
1985	159,522	30,277	8.25	23,175	17,216	15,673	1,543
1986	158,922	30,135	8.43	23,175	17,140	15,286	1,854
1987	153,986	29,210	7.91	23,175	16,517	15,765	752

Source: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids, Energy Information Administration, Annual Reports.

1. Reported wet (with liquids) by EIA. The values listed have been corrected to dry volumes.
2. These reserve life indices were calculated for the lower-48 states using only the proved reserves in producing reservoirs. Hence, these values are lower than the indices normally reported.
3. Production potential is the difference of lower-48 reserves (column 2) and the average reserves in nonproducing reservoirs (1977-1981) (tabulated in column 5) divided by the average reserve life index (column 4) from 1977 to 1981. This value is an estimate of the total deliverability of the gas reserves.
4. Lower-48 dry production.
5. Estimates of incremental production which could come from the larger-than-usual volume of nonproducing reservoirs.

In Table 1, the average nonproducing reserves from 1977 through 1981 were subtracted from the lower-48 nonproducing reserves (dry). These differences were divided by the average reserve life index from 1977 to 1981 (7.92) to develop the hypothetical production shown in column 6. The subtraction of the actual production from the hypothetical production volumes establishes the potential increase in production from nonproducing reservoirs shown in the final column.

These volumes vary from 752 to 2,514 Bcf and are an indication of the large production capability that was not being used from 1982 to present. These volumes are consistent with the estimates of 250-750 Bcf within 12 months and 500-1,000 Bcf within 36 months as shown in Table 6. This range is intended to reflect the varying time delays for these reserves to be put into production and the range of possible production rates specific reservoirs could produce.

D. Canadian Gas

Canadian gas has been imported for use by U.S. gas customers for over 30 years. Canada is a close business partner of the U.S. and these supplies are secure, reliable and plentiful. Canada has varied its exports to the U.S., in accordance with U.S. demand, to levels as high as 1.3 Tcf per year.

The Canadian gas producers also experienced a bubble in the early 1980s. Canada could produce more gas, but the combined domestic and export demand has been inadequate. In 1988, Canada produced 3.6 Tcf from total marketable natural gas reserves of 94.8 Tcf (see Table 2). If only the conventional areas are considered, the Canadian marketable reserves were 70.0 Tcf at year-end 1988 -- a reserves to production ratio of 20 to one. In the lower-48 the U.S. reserves to production ratio is about ten to one. The implication is that Canada has a much greater production capability than it currently is using.

Table 2

Canadian Marketable Natural Gas Reserves and Production
(in Tcf)

At Year-End	Remaining Reserves[1]	Net Production[1]	Reserve Life Index[2]
1980	88.4	2.5	35.6
1981	91.0	2.4	37.8
1982	92.0	2.5	37.3
1983	92.7	2.2	41.7
1984	99.7	2.8	35.6
1985	98.3	2.9	33.8
1986	97.4	2.7	35.7
1987	95.6	2.8	33.7
1988	94.8	3.6	26.4

Note: Volumes are calculated at a pressure base of 14.65 psia and a standard temperature of 60°F.

1. Rounded to the nearest tenth.
2. This statistic includes the so-called "frontier areas." Production is typically low in the frontier areas (less than 5 Bcf) but reserves are large (almost 25 Tcf). If the reserve life index for 1988 is calculated excluding the frontier areas, the reserves are 70 Tcf, production is 3.6 Tcf and the reserve life index is just under 20.

The Canadian National Energy Board (NEB), which sets policy and export regulations, has been adjusting its rulings throughout the late 1980s to make Canadian gas more available at competitive prices. Table 3 shows the volumes and prices of Canadian imports from 1972 to 1988. Current contracts could support an increase of Canadian imports to 1.5 Tcf per year. This level of 1.5 Tcf/yr. could be reached without further major construction; however, to maintain full delivery flexibility to key U.S. regional markets, some construction would be required. If more than the currently contractually authorized export levels were to be made available, pipeline construction would certainly be needed, not only in some of the border states but also into new major consumption regions in the U.S. Some of this needed construction has already been proposed to Canadian and U.S. regulatory authorities. Some of these proposals are long term projects; others are for spot gas deliveries. If these projects were encouraged and the necessary pipeline construction undertaken, annual imports from Canada could increase to 1.8 Tcf in the early 1990s.

Table 3

Pipeline Imports from Canada - 1972-88

Year	Volume Bcf	Average Price[1] $/MMBtu	Total Revenue[2] $ Billion
1972	1,009	0.30	0.3
1973	1,028	0.34	0.4
1974	959	0.54	0.5
1975	948	1.18	1.1
1976	954	1.69	1.6
1977	997	1.94	2.0
1978	881	2.15	1.9
1979	1,001	2.57	2.6
1980	797	4.28	3.5
1981	762	4.80	3.7
1982	783	4.92	3.9
1983	712	4.45	3.2
1984	755	4.01	3.1
1985	926	3.18	3.0
1986	749	2.51	1.9
1987	992	2.19	2.2
1988	1,283	2.06	2.7

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[1] Calculated assuming approximately 1.02 thousand Btus per cubic foot.

[2] Revenue amounts are derived from the product of volume and average price.

SOURCE: A.G.A., Gas Energy Review, May 1989.

Canadian gas reserves can be operated at relatively low production costs. Most of the wells have been drilled; much of the processing and gathering equipment is already in place. Therefore, a large percentage of the finding costs are "sunk costs" to the Canadian producers. Some of their gas wells have been shut in and could be produced at wellhead prices only marginally above operating costs. For these reasons the additional Canadian gas potential of 400 Bcf is believed to be economically viable within 12 months. With a longer lead time such as 36 months, volumes of 500 Bcf are achievable in the early 1990s.

Table 4 provides some detail regarding the current pipeline capability and how these larger import volumes could be achieved. Any significant increase in imports above the 150 Bcf per month level will certainly require more pipeline capacity.

Table 4

Canadian Natural Gas Export Capacities

	Monthly	Annual
Peak Winter Day Capability	155 Bcf[1]	1,825 Bcf[2]
Peak Month/Year Demonstrated	138 Bcf[3]	1,283 Bcf[4]
Peak with Expansions by 12/31/90	155 Bcf[5]	1,860 Bcf[6]
Estimated Capability by 1995		1,800 Bcf[7]
Estimated Capability by 2000		2,000 Bcf[7]

1. Current peak capability if maintained for 31 days; probably not sustainable for a longer period of time.
2. Theoretical capability only; calculated by multiplying 5 Bcf/d by 365.
3. Demonstrated in January 1988; some minor additional capability existed at that time but was not used.
4. Demonstrated for the 12 months of 1988.
5. Planned expansions including those at Niagara Falls, Iroquois, Highwater.
6. Theoretical capability obtained by multiplying 155 Bcf per month by 12.
7. These levels are achievable only with upgraded pipeline facilities in Canada and the U.S.

E. Accelerated Infill Drilling

In some major gas fields such as Hugoton (Kansas, Oklahoma and Texas) and San Juan (New Mexico), infill drilling has the potential to increase both the reserves and the deliverability. The reserves increase would result from a more complete recovery of the gas-in-place. The deliverability increases would result from an increased capacity to take gas out of the reservoirs. Such drilling can be optimized based on the extensive experience and knowledge of the region. As a result, infill drilling tends to be better cost-controlled and result in fewer unsuccessful wells. Therefore, when state conservation commissions authorize closer well spacing, such wells are often drilled relatively quickly and begin production more rapidly than wells in a new field might be.

In the Hugoton field, infill producers predicted potential reserve increases of as much as 7.6 Tcf. Infill drilling in the San Juan area has been in progress for some years. Increases of as much as 1.4 Tcf of additional reserves might be possible there. The production increases on a national basis due to infill drilling could be as high as 400 Bcf per year.

Programs for infill drilling are dependent upon state well spacing determinations and the ability to sell the increased gas production (no change in federal law or regulations is necessary for this gas to become available). Generally, the state regulatory bodies favor infill drilling as a means of enhancing state tax and royalty revenues. Nevertheless, conditions for the sale of the gas still limit what drilling is likely to be initiated by the producers.

Infill drilling is, of course, sensitive to the timing to initiate the drilling programs. In Hugoton and San Juan, some infill production could be developed within 12 months. About 50 to 100 Bcf of additional production from infill drilling would be feasible within 12 months. In a 36 month period more production could become operational. Volumes of 100-400 Bcf are reasonable annual production levels that could be achieved.

In addition to the infill drilling there is also the development drilling that has been planned as a result of past exploratory activity. These gas resources could also be brought into production relatively quickly. This analysis does not consider new production capability from development drilling because such reserve additions and new production are part of the normal exploration and production activity and are a traditional gas source. New gas production capability from infill drilling would come from previously discovered reserves, and any new reserve additions from such activity would be generally classified a "revision." On the other hand, new production from development drilling would come from new gas discoveries.

Although Table 6 shows the increased production potential for nonproducing reservoirs and infill drilling separately, it is interesting to examine the growth in nonproducing reserves in the areas with high potential for infill drilling. In two of the most important infill areas, Kansas (Hugoton field) and the San Juan Basin of New Mexico, EIA has reported some small increases in proved reserves since 1985 but major increases in the volumes of reserves in nonproducing reservoirs. The EIA and A.G.A. Committee on Natural Gas Reserves (CONGR) data are shown in Table 5. The CONGR data are available at the individual field level and have already reported results for 1988. In Kansas, 90 Bcf of nonproducing reserves were reported at year-end 1984. By year-end 1987, this category had increased to 268 Bcf, i.e., almost

tripling in size. Similarly, in West New Mexico, 213 Bcf of proved reserves in nonproducing reservoirs was reported at year-end 1984. At year-end 1987 this volume was reported to be 1,613 or an increase of over seven fold.

This large growth in nonproducing reserves suggests that the additional nonproducing gas reserves could be produced and marketed somewhat more rapidly than new discoveries. No exploration effort, leasing or extensive contract delays would slow the development of a production capability with this gas.

Table 5

Nonproducing Natural Gas Reserves in High Potential Infill Regions
(in Bcf)

	1983	1984	1985	1986	1987	1988
Proved Reserves						
New Mexico-West[1]	8446	8167	7866	9114	8739	
San Juan Basin[2]	8081	7756	7591	6563	6324	6230
Kansas[1]	9553	9387	9337	10509	10494	NA
Hugoton[3]	10112	9823	9508	9189	8926	8588
Nonproducing Reserves						
New Mexico-West[1]	90	213	NA	1890	1613	
Kansas[1]	83	90	NA	254	268	

1. As reported in U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Reports, EIA.
2. A.G.A. Committee on Natural Gas Reserves (CONGR) in Natural Gas Reserves of Selected Fields in the United States and of Canada, Annual Reports, A.G.A. Data shown is for the San Juan Basin Mesaverde only.
3. A.G.A. Committee on Natural Gas Reserves (CONGR) in Natural Gas Reserves of Selected Fields in the United States and of Canada, Annual Reports, A.G.A. Data shown is for the Kansas portion of the Hugoton field only.

F. Liquified Natural Gas (LNG)

In 1988, about 8 Bcf was received as LNG at the Distrigas terminal in Everett, Massachusetts. Large LNG terminals at Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana are capable of handling much larger volumes of imports. Although each of these terminals was operational for some time in the 1978-1983 period, today they are inactive because pricing levels for imported LNG are not generally competitive. These four terminals have the capability of receiving the LNG equivalent of about 850 Bcf annually.

LNG trade is still growing on a worldwide basis: from North Africa to Europe, from the Middle East to Japan, from Oceania to Japan and Korea and from Alaska to Japan. More than 20 nations currently export LNG or are likely to initiate LNG export projects in this century. There is a large world resource base for gas and, if the gas price in the U.S. permits the net-back to the exporting nation to be large enough, an LNG trade can be anticipated.

On balance, if demand exists in the U.S. at wellhead prices of $2-3 per Mcf or more, LNG imports could increase greatly by 1990. Within 12 months 40 Bcf could be imported at the Distrigas terminal alone and as much as 100 Bcf might be expected if both the Distrigas and Lake Charles terminals were operational. Higher import volumes would involve greater utilization of other terminals, which would be reactivated. From a physical capability viewpoint, by 1992 two major terminals could be fully operational, which would allow even higher import levels (possibly as much as 200 Bcf) to be achieved.

G. Twelve Month Responses

Given the free market for gas, as it exists today, tightness in gas supply is likely to cause sufficient gas price increases to cause new supplies to be developed. As shown in Table 6, the Canadian gas imports could provide increased volumes of gas even within 12 months -- a level of 400 Bcf per year is estimated. Nonproducing gas and accelerated infill drilling could also be developed very rapidly. The 250-750 Bcf for nonproducing gas is a short term productive capacity. Infill drilling could also be developed rapidly with levels of 50-100 Bcf judged to be reasonable. LNG imports could increase 40-100 Bcf within 12 months. In total, an increase in natural gas availability of 700-1,350 Bcf is possible.

H. Thirty-six Month Response

If demand warranted a longer term supply build-up, additional volumes of natural gas could become available. The longer time frame would allow more development of the nonproducing reserves. This production capability would rise to 500-1,000 Bcf. The Canadian import capability would increase as a result of additional pipeline construction and increased development drilling by Canadian producers. The estimated 500 Bcf increase would provide a total volume of Canadian imports to reach 1.8 Tcf in 36 months. LNG imports could also rise to 200 Bcf as the importing terminals achieve full operational status. In total, these four sources of natural gas supply could account for an additional 1,300-2,100 Bcf in 36 months.

I. Peak Demands

This study addresses only the annualized need for gas to achieve a balance between supply and demand. There is very little slack in a balanced market to facilitate shifting supplies to meet the daily peak load requirements. It is important for that reason to evaluate the readiness of underground natural gas storage and propane-air facilities to handle peak loads. The status of these important facilities are described in A.G.A. Engineering Technical Note US-89-2-1, June 1989, "Underground Storage of Gas in the U.S. and Canada - 1988 Data" and A.G.A. Engineering Technical Note SS-89-3-1, August 1989, "Propane-Air Plant Statistics." The underground storage report cites the cumulative maximum day output from underground storage in 1988 as 39.1 Bcf, up from 36.7 Bcf in 1987. The latter study cites the demonstrated capability of propane-air plants to add 4.2 Bcf (equivalent) per year to the natural gas utility industry.

J. Total Supply

Table 6 lists the four incremental sources of gas. The capabilities for near-term (within 12 months) and the longer term (within 36 months) are tabulated. In the near-term, 0.7-1.4 Tcf of additional gas supplies could become available. In contrast, in 36 months between 1.3 and 2.1 Tcf/yr. could be made available. These supplies will act as bridge sources of natural gas during the time it takes the exploration and production industry to explore for and develop new longer-term supply sources.

Table 6

Possible Incremental Short Term Gas Supply Potential
(in Bcf)

	Within 12 Months	Within Three Years
Nonproducing Reserves	250-750	500-1,000
Canadian Gas[1]	400	500
Accelerated Infill Drilling	50-100	100-400
LNG[2]	40-100	200
Total Additional Supply Available	700-1,350	1,300-2,100

---

[1] Volumes are in addition to the 1,283 Bcf estimated to be imported in 1988.
[2] Volumes are well below the physical limitations of the existing terminals.

Footnotes

1. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, *Energy Information Administration, Annual Reports.*
2. *"Natural Gas Production Capability: 1989-1990," Issue Brief 89-11, American Gas Association, July, 1989.*
3. *Oil and Gas Journal, Vol. 86, No.52, December 26, 1988, p. 49.*
4. *Petroleum Intelligence Weekly, Vol. 27, No.21, May 23, 1988, p.5.*

A.G.A. American Gas
Association

Natural Gas for the Winter Heating Season

A Report of the A.G.A. Gas Supply Committee
September 1989

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Executive Summary

The analysis described in this report, as well as extensive survey data generated from producers, pipelines and distributors, concludes that on a national average basis there should be adequate gas deliverability this winter. Gas supplies in the winter 1989/90 will reach the market through different suppliers than in recent history. Storage and spot gas will supply a larger percentage of distributor requirements. In contrast, pipeline system gas will be 41 percent of total peak month requirements in January 1990 compared to approximately 76 percent in January 1980. However, the ability of spot gas to satisfy seasonal requirements remains essentially untested. Evidence from the winters of 1987/88 and 1988/89 indicate the potential for spot price volatility. In addition, growth in gas demand in certain regions coupled with the above shift in gas supply mix may result in short-term regional supply discontinuities.

On a national average basis, January 1990 gas production capability is expected to be 10 percent lower than January 1980 *actual* production. On the other hand, gas storage send-out capability in January 1990 will be 51 percent greater than actual 1980 storage withdrawals reported by the Energy Information Administration.

- On a national basis, no imbalance between supply and demand is expected. The maximum monthly consumption of gas ever recorded in the U.S. was 2,426 Bcf in January 1979. A peak supply capability for the winter of 1989/90 is projected to be 2,444 Bcf. This supply forecast is based on:
    - maximum sustainable monthly production in 1990 (January) conservatively estimated at 1,600 Bcf — ten percent below the actual level of production in 1980
    - peak month storage withdrawal capability of 700 Bcf in 1990 up from 576 Bcf actual withdrawal in 1988; 697 Bcf is the highest demonstrated one month withdrawal capability
    - Canadian gas supplies (which provided almost 1.3 Tcf to the U.S. in 1988) are expected to be able to surpass the record monthly level of 138 Bcf established in January 1988 to 150 Bcf in January 1990.
- The A.G.A. survey for the first time included major gas producers. Producer respondents quantified the shift from committed gas sales in January 1980 of 98 percent of their sales to an expected 49 percent of sales in January 1990. These same producers described the purchasers of their gas in 1980 as 75 percent pipelines and 25 percent LDCs and end-users. These sales in January 1990 are expected to be 21 percent to pipelines, 25 percent directly to LDCs and 54 percent directly to end-users.
    - In response to a question concerning their gas supply expectations, if January 1990 were the coldest month in fifty years, the producers believed supplies would be adequate for all firm customers. Interruptible customers were likely to be interrupted during such a cold month. Spot market prices were expected to respond in a manner similar to the seasonal spot market variations observed in the past several years.
- **As a result of a massive restructuring in the pipeline industry, system gas deliverability, (i.e., pipeline sales which includes production from dedicated reserves), has been reduced significantly throughout the 1980s.**
    - To alleviate take-or-pay obligations and facilitate settlements, pipelines have released large quantities of committed gas reserves and deliverability. From 1985 to 1990 the companies in the A.G.A. survey are expected to release over 45 Tcf of reserves (over a quarter of the nation's lower-48 proved reserves).
    - Large quantities of pipeline reserves have been released causing a decrease in system gas deliverability. The pipelines which participated in the A.G.A. survey have lost about 40 percent of their system gas delivery capability since 1980.
    - The gas reserves and deliverability released by interstate pipelines now are the backbone of the spot market — it is the same gas but has radically different contractual and regulatory obligations.
- The mix of gas supplies available to interstate pipelines has changed between 1980 and 1990. The principal change in pipeline supply has been the purposeful reduction in dedicated gas supplies due to reduced demand from traditional customers.
    - Long-term field purchases

  for system supply accounted for 76 percent of pipeline throughput in 1980, but now contributes 41 percent.

  - Transportation represented only 5 percent of pipeline throughput in 1980. Transportation is expected to be 35 percent of throughput in January 1990.
  - Gas from storage will continue to be important, growing from 19 percent in 1980 to 24 percent, if needed, to satisfy the demand in a very cold winter.

- In January 1980, LDC requirements for system gas were 82 percent of the LDC total requirements for peak month gas. In contrast, LDC purchases of system gas are anticipated to be only 59 percent of their total send-out in 1990.
- LDCs have diversified their gas supply sources principally for cost reasons. Forecasts for the 1990 winter indicate that these trends will cause a major change in the mix of LDC supply from 1980 to 1990.
  - To offset the system gas supplies that were not purchased, LDC send-out of spot gas increased in this time period from 0 to 13 percent.
  - LDC send-out from other sources such as SNG grew from 18 percent in 1980 to 28 percent in January 1990.
- Spot gas, which represents the vast majority of LDC owned/committed gas, has substantially replaced system gas during both peak and off-peak periods. While this displacement is most severe during off-peak periods, it has also grown during periods of peak seasonal requirements.
  - The ability of spot gas to satisfy seasonal gas requirements is basically untested during a period of relative gas supply/demand balance.
  - The primary mechanisms for spot gas volumes to react to increased demand, such as cold weather, are through increases in spot prices and fuel switching. The price variations were clearly demonstrated during the last two winter heating seasons. Such temporary price run-ups and run-downs are likely again this winter. Several factors indicate that spot market prices are likely to become more volatile. The demand for spot gas is growing because spot gas is often less expensive than system gas. Additional factors which influence the variations in spot market sales are: (1) total gas demand is increasing (2) pipeline system sales are declining (3) supply, in terms of national production capability, is declining and (4) LDC and pipeline purchases of spot market gas will reinforce demand during cold weather.
- Spot market price volatility was evaluated for an extraordinarily cold month by the LDC survey respondents. They estimated that they would pay only 4.8 percent more for gas in January 1990 than they did in January 1988.
- As previously noted, the release of dedicated reserves by interstate piplines has resulted in the produced gas being purchased directly by LDCs (both spot gas and longer-term contracts). The change in ownership of this produced gas and how it reaches the marketplace could be an important factor during periods of peak demand.
- Additionally, these new mechanisms imply that redistribution of gas supplies during periods of peak demand will be accomplished by contract-price bidding instead of federally established curtailment priorities.
- On balance, adequate gas supply is anticipated during the coming winter. On the other hand, transportation bottlenecks and sharp swings in gas demand associated with cold weather are likely to lead to price volatility on the spot market. During short periods in localized areas, this could even result in physical delivery constraints on getting gas.
- This study tests the capability of the gas industry if severe cold weather occurs in an abnormal January with the preceding December and the following February reflecting typical temperature patterns. The analysis of the strain on the system which would occur if the extremely cold weather extended over a three month period is not reflected in this report.

Chapter 1
Introduction

The transportation segment of the gas utility industry has changed rapidly—both structurally and functionally. With many aspects of the transition still not resolved, an unusually cold winter heating season could stress the gas delivery system and create both price volatility and physical delivery problems in certain geographic regions. To date, the most severe test of the spot market and the new transportation arrangements occurred in January 1988.[1] Spot market prices surged rapidly in response to increased demand and a lack of flexibility relative to receipt and delivery points. With another winter heating season approaching, regulators and end-users wish to review recent trends and gain insights into the likely supply-demand- price interactions.

This report initially reviews historical supply-demand data from 1973 through 1989. This information provides the basis for the conclusion that no national supply-demand imbalance is likely to occur in any month of the coming winter heating season. However, as the pipeline system gas sales and committed reserves are considered, it is apparent that new mechanisms (e.g., brokering, producer- to-LDC direct sales, transportation, best efforts storage, best efforts sales to industrial customers) have become more important during the peaks of the winter heating seasons. Gas supplies have often been subject to price surges for all customers and supply disruptions to interruptible customers. Adjustments made by the gas utility industry to reduce end-user vulnerability to such events are outlined in this analysis.

Beyond the testing of the new mechanisms in the marketplace, the spot gas price variations become an issue of great importance to all — producers, pipelines, distributors and end-users. The report concludes that spot gas prices have become increasingly volatile, that spot prices now influence almost all gas prices, and that spot price volatility has followed seasonal demand patterns.[2]

The methodology to develop the aggregate statistics presented in this analysis that describe gas supply and send-out volumes, reserves and pricing data began with a survey of all A.G.A. member companies, pipeline and distribution alike. In addition, major producers were asked to contribute data on their gas sales and obligations. Each pipeline company was asked to supply data regarding system, storage and transportation gas for the months of January 1980, 1985, 1988, and 1990. Local distribution companies (LDCs) were asked to provide data on gas supply and send-out for the same time period. Actual data were reported for January 1980, 1985, 1988 and estimated data for 1990. Pricing information was also requested of all gas utilities. All companies were asked to base their January 1990 estimates on the assumption that this would be the coldest January in 50 years. Therefore, for January 1990 a near worst case scenario is presented: the supply, transportation and delivery systems are assumed to be under a maximum stress.

Survey replies include gas supply data from 28 pipeline companies and 73 LDCs. Pipeline company responses represent a broad geographic distribution as well as a broad range of company sizes. Likewise, LDCs replying are geographically diverse, include small and large distribution systems and include companies with customer bases anchored by residential, commercial and industrial sales and combinations of the three. In order to present data and conclusions on a national scale, inputs from survey responses are aggregated rather than presented individually. This technique also protects those companies that provided information considered proprietary or confidential.

Chapter 2
Gas Supplies and Demand

In assessing the adequacy of gas supplies for the 1989-1990 winter, this report examined both supply availability and gas demand projections. The supply estimates of this portion of the report are based on how much gas could be supplied from each source for which good statistical data are available—conventional production, imports, etc. This total volume, which could be available in January 1990, is compared to the record level of monthly consumption in the U.S., which is used as a demand constraint. These potential supplies exceed the highest monthly consumption ever recorded in the U.S. Only if demand in January 1990 exceeded the historic high, could one anticipate a national volumetric gas supply problem. Supply availability could also be affected by a sustained (several months) cold period that would reduce storage supplies. On the other hand, the ongoing restructuring of the gas industry could create other types of supply problems. It is important to realize that the

Table 1
Maximum Monthly Gas Supplies and Consumption - 1973 through January 1989
(in Bcf)

Year	Production[1]	Domestic Supplementary Gas[2]	Imports[3]	Storage Withdrawal[4]	Consumption[5]	Data Sources
1973	1912 [6]	--	79	--	2348	*Monthly Energy Review*, Dec. 75
1974	1849 [6]	--	86	--	2230	*Monthly Energy Review*, Dec. 76
1975	1705 [6]	--	84	371	2248	*Monthly Energy Review*, Dec. 76
1976	1677		86	526	2291	*Monthly Energy Review*, Jan. 79
1977	1665		101	670	2407	*Monthly Energy Review*, Jan. 79
1978	1672		87	668	2385	*Monthly Energy Review*, Jan. 79
1979	1751		114	673	2426	*Monthly Energy Review*, Dec. 83
1980	1777	18	118	465	2263	*Monthly Energy Review*, Mar. 84
1981	1684	20	93	571	2279	*Monthly Energy Review*, Aug. 85
1982	1657	19	110	697	2400	*Monthly Energy Review*, Aug. 85
1983	1530	17	112	634	2191	*Monthly Energy Review*, Mar. 87
1984	1629	17	97	563	2219	*Natural Gas Monthly*, Feb. 88
1985	1559	13	106	661	2148	*Natural Gas Monthly*, Feb. 88
1986	1536	12	99	421	2106	*Natural Gas Monthly*, Feb. 88
1987	1533	11	121	521	2051	*Monthly Energy Review*, Apr. 89
1988	1535	17	138	576	2168	*Monthly Energy Review*, Apr. 89
1989	1503	16	119	397	2008	*Monthly Energy Review*, Apr. 89

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[1] Dry gas production.

[2] Includes SNG from liquid hydrocarbons, propane-air, LNG storage, landfill gas, coke oven gas.

[3] Canadian gas and LNG imports.

[4] Underground storage withdrawals.

[5] As reported by EIA.

[6] Reported as marketed production. These statistics have been adjusted to represent dry gas production using a factor of .959 which is based on 1977-78 data for March and December.

[7] January - June only.

Table 2
Estimated National Maximum Supply and Consumption Levels For 1989-1990 Winter

Source	Volume in Bcf	Remarks
Conventional Production	1,600	1,629 Bcf was demonstrated in January 1964; 1,534 Bcf was demonstrated in January 1988
Storage withdrawal	700	697 Bcf withdrawal occurred in January 1982
Domestic Supplemental Sources - propane air, LNG storage, landfill gas,	17	17 Bcf was demonstrated in January 1988
LNG Imports	2	2.8 Bcf is a maximum shipload (129,500 cubic meters)
Canadian Gas Imports	150	138 Bcf was demonstrated in January 1988; 150 Bcf is based on pipeline capacity
Exports, Storage Injections	(25)	Based on minimum storage injections and exports historically
Total Supply Capability	2,444 Bcf	
Maximum Consumption January 1979	2,426 Bcf	

concern is not the level of gas available on a national basis — rather it focuses on the ability of that gas to get to market.

Table 1 tabulates the highest monthly gas supplies and consumption levels for each year from 1973 through May of 1989. The highest supply reported by the Energy Information Administration (EIA) for any month in each year is listed. The conventional production maximum could have occurred in one month and the maximum for withdrawal from storage could have occurred in another for a given year. In the table only the supply for the highest month in the year is listed. Inasmuch as the supplies are largely independent, the maximization of one source does not argue against the other sources being maximized.

Conventional production is by far the largest supply source with the monthly maximum values ranging from the 1,530 Bcf to 1,503 Bcf lows in 1983 and January 1989, respectively (undoubtedly demand restrained) to the peak of 1,912 Bcf in 1973. Maximum monthly underground storage withdrawals vary greatly also—a low of 371 Bcf in 1975 to the high of 697 Bcf in January 1982.

Domestic supplemental gas sources contribute locally important volumes of gas, but nationally the total gas supply is only about 11-20 Bcf per month. The peak level in recent years was the 17 Bcf which was produced in January 1988. This category includes propane-air, LNG storage, landfill gas, SNG from liquid hydrocarbons, coke oven gas, etc.

Imports include Canadian, Mexican and LNG shipments. The data tabulated in Table 1 are primarily Canadian gas; however, Mexican gas imports are included for the years 1977 and 1980 through 1984; LNG imports are incorporated in the years 1973 to 1986 and 1988.

Storage withdrawals are based on EIA-191 survey results. The volumes reported do not reflect the injections of gas into storage even though they may have occurred in the same month. Typically gas is being injected into storage every month. Withdrawals are usually about ten times greater than injections during the winter heating season. For the purposes being considered here, a maximum withdrawal capability is used in Table 1. Table 2 includes an allowance for injection of gas into storage.

Consumption statistics are also EIA data and include all normal consumption categories as well as the gas allocation made by EIA as "unaccounted for".

Table 2 combines the sources of supply at the maximum level which might be available in January 1990 and compares that total to the maximum recorded level of consumption (which occurred in January 1979). This maximum consumption level was 2,426 Bcf. Aggregate supplies available for January 1990 were projected to be 2,444 Bcf. Therefore, on a national basis there appears to be an adequate supply of natural gas to satisfy requirements even if consumption equalled the record level set in 1979. This evaluation does not consider the regional issues. For example, some regions of the country face "receipt point" problems relative to gathering and transportation. Other regions face delivery point problems. These issues are considered in other chapters. Also omitted in Table 2 is the potential impact on these sources of supply from Acts of God such as severely cold weather causing producing wells to freeze up or hurricanes in the Gulf of Mexico, either of which could limit regional production to only a fraction of its normal level.

Demonstrated conventional production (dry) was in excess of 1,600 Bcf in four of the years from 1980 to 1988. In 1980 the production level was 1,777 Bcf. The estimate of current capability uses the data in Tables 2 and 3. Table 3 presents a tabulation of the daily production rates for the month of maximum production for six major gas producing states and the total U.S. The final five columns of the table show the ratios of the production in that state for 1985, 1986, 1987, 1988 and the first two months of 1989 as compared to 1980. The general conclusion is that while production levels are typically lower in the later years, the capacity to produce gas nationally has been demonstrated at 88-90 percent of the 1980 level. At worst, the data indicate a decline of ten to twelve percent. At best, there has been no loss in production capability at all. The worst case would be valid if actual February 1989 production (52.2 Bcf per day) was the maximum capability; the best case would be if February 1989 production could have been higher, but the full capability was not achieved because of reduced production associated with limited demand.

The 1,600 Bcf monthly production capability is based on a nominal ten percent loss in production from 1980 to 1988 as indicated in Table 3. If this reduction is applied to the 1980 peak month production in Table 1, a level of 1,600 Bcf is suggested. Unusually strong reserve additions for the lower-48 states in 1988, as reported by EIA, suggest a reserve base capable of this level of production. Also, a greater percentage of the total drilling activity is now apparently gas oriented. This may indicate a stronger gas oriented response when drilling activity returns to the higher levels of the early 1980s.

In 1984, many Texas wells were shut in by freezing weather which severely limited production at that time. Subsequently, there has been extensive speculation that the Texas gas production capability could be significantly lower than it was in 1980.[3] Table 3 statistics on Texas production indicate that in 1988 the Texas production level was demonstrated at 90.9 percent of the maximum production level achieved in any year since 1980.

On balance, the 1,600 Bcf level seems to be a conservative assessment of what the maximum dry conventional production for the U.S. might be for the peak month during the 1989-90 winter heating season.

Storage withdrawal capability is listed in Table 2 as 700 Bcf. This level is 3 Bcf higher than the maximum month withdrawal in January 1982. Many factors influence this estimate. (See Appendix I for historical statistics on underground gas storage.) The single most important factor is the quantity of gas in storage at the start of the month. For example, in January 1982 the total gas in storage at the beginning of the month was 6,569 Bcf. At year-end 1988, 6,672 Bcf was in storage. How much gas would be in storage at year-end 1989 is unknown. However, as will be discussed in Chapter 3, there is an expectation that storage will be a more important part of pipeline supplies this winter so that one could assume that storage will be relatively full at the start of the winter heating season.

Domestic supplemental sources describe a variety of types of gas—SNG from liquid hydrocarbons, propane-air, LNG storage, landfill gas and coke oven gas. It may be that the demonstrated 17 Bcf for January 1988 is lower than might be obtained from these sources. For example, seasonally operating SNG plants have a design capability to produce 19.5 Bcf in a 31-day month.[4] However, in the 1987 - 88 winter heating season these plants produced only 4.1 Bcf. Economics are the primary cause of this low production level. If competitively priced naphtha, propane, butane, etc. were available during a period of peak demand, higher production levels would be possible. Despite this potential, the January 1988 demonstrated level of 17 Bcf is listed in Table 2.

LNG imports could easily provide the 2 Bcf listed in Table 2 into the Distrigas terminal at Everett, Massachusetts. If the Lake Charles facility is operational (an authorization for operation has been requested), LNG imports could be substantially higher.

Canadian gas imports were 138 Bcf in January 1988. Although many of the import lines were operating at full capacity during January, not all of the importing systems did receive the full import capability. Maximizing the flow of gas at each import point could raise the level for a month to 150 Bcf.

Deductions of gas supply for storage injections and exports are shown in Table 2. This level of 25 Bcf is consistent with historic low levels of injections and exports. Geographically, the gas exports are primarily from southern Alaska to Japan, and the storage injections usually occur in areas where gas demand is not extreme. Therefore, these volumes would not seriously affect the gas supply in areas of peak demand. However, Table 2 includes them for completeness.

Table 3
Demonstrated Natural Gas Production In Peak Months

	Daily Production Demonstrated In Peak Month*										Ratios				
State	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989[1]	1985/1980	1986/1980	1987/1980	1988/1980	1989/1980
Kansas	3,270	2,188	2,191	2,057	1,967	2,194	1,903	1,929	1,948	1,607	.671	.582	.590	.596	.491
Louisiana	20,446	19,686	18,709	15,928	18,535	16,537	15,814	15,112	15,088	15,117	.809	.773	.738	.738	.739
New Mexico	3,339	3,339	3,307	2,972	3,061	3,148	2,420	2,804	2,727	2,551	.943	.725	.840	.817	.764
Oklahoma	6,444	6,252	6,611	5,606	6,182	6,246	5,846	5,932	5,698	5,964	.969	.907	.921	.884	.926
Texas	20,143	19,511	19,013	17,483	18,482	18,284	18,036	18,382	18,309	17,573	.908	.895	.913	.909	.872
Wyoming	1,308	1,345	1,378	1,509	1,588	1,356	1,502	1,690	1,981	2,247	1.037	1.148	1.292	1.515	1.718
U.S.	59,061	55,974	55,749	51,763	55,881	53,054	52,077	51,862	51,909	52,201	.898	.882	.878	.879	.884

* in MMCF
1 January-February only.

Source: EIA, *Natural Gas Monthly*, April 1989

Chapter 3
Pipeline Company Trends

Most major pipeline systems provided A.G.A. with statistical data and projections of supplies and requirements covering the period from 1980 through 1990. These pipelines report that there has been a major reduction since 1980 in the demand for system gas. The term "system gas" is used in this report to describe gas sold by the pipeline. It includes the gas acquired by the pipeline from dedicated production, purchases from other pipelines and storage. As a result of this decreased demand for system gas, the pipelines have released large amounts of committed gas and/or sold their company-owned gas reserves. Although a portion of this gas can be "recalled" by the pipelines, no quantification of the volume which could be recalled is available. Figure 1 shows the decline since 1980 when 88.6 Tcf was under pipeline control to 1990 when only 36.7 Tcf will be owned or committed to the pipelines. Although the 58.6 percent drop in reserves was necessary to stem the growth of take-or-pay obligations, the loss in reserves sharply reduced the pipelines' capability to deliver system gas. However, the pipelines are still transporting the traditional quantities of gas. Today, the combination of transportation gas and system gas satisfies the pipeline customers' demand for gas. The question to be answered is, if a severely cold winter occurred, would the transportation gas plus system gas be adequate to satisfy demand? There is very little doubt that system gas supply capabilities have been reduced to the point that system gas would, by itself, be unable to satisfy the same share of a peak month load as it did in earlier years. Volumetrically, transportation gas plus system gas is adequate to satisfy demand as shown in Table 2. The flexibility of this system to satisfy seasonal requirements remains essentially untested.

Pipelines have experienced a sharp reduction in the purchases of system gas (see Figures 1 and 2). For the pipelines that responded to the A.G.A. survey, the percentage shares of total deliveries are shown in Table 4. The decline in system gas sales was from the January 1980 level of 76 percent of deliveries to the January 1990 level of 41 percent—a loss of 35 percent. Not surprisingly, these same pipelines reported that they have reduced their committed gas supplies by 58.6 percent. From 1985 to 1990, the quantities of gas being

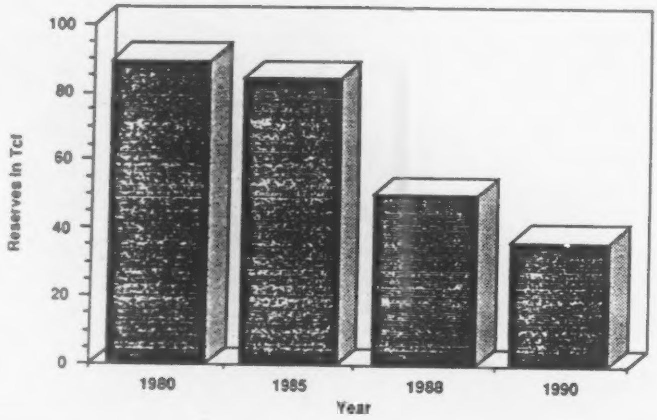


Figure 1
Reserves Owned By/Committed to Pipelines
1980-1990
(in Tcf)

released exceeded 45 Tcf. In addition to the released gas, pipelines' committed reserves have been declining as a result of production. Since these reserves have not been replaced, the decline in committed reserves is exacerbated.

The release of gas committed to the pipelines has been an important element in both take-or-pay settlements and reduction in accrual of new take-or-pay obligations.

Offsetting this decline in system gas were the major increases in transported gas shown in Figure 2. Survey respondents reported increases in transported gas from 69 Bcf in January 1980 to 554 Bcf estimated for January 1990.

At the reduced level of commitments system gas delivery capabilities have been reported in aggregate to be about 40 percent lower than they were in January 1980. (Note: deliverability has tended to fall less rapidly than reserves due to increased capability to produce committed reserves faster.) To provide a maximum delivery of system gas in January 1990, the mix of pipeline supplies would be quite different from the mix in January 1980. This transition is reflected by the percentage shares of pipeline supplies as shown in Table 4. In Table 4, January 1980, 1985 and January 1988 data characterize the changes with actual statistics on what occurred in those months. The January 1990 estimates, in contrast, are the estimated levels of system gas which could be provided with strong demand. Clearly, the role of system gas is less now, due to released gas, than it was in 1980. Furthermore, system gas now includes some spot gas purchases by pipelines. Storage has become much more important, rising from 19 to 24 percent. In addition to increased percentage shares, the actual volumes of gas expected from storage also are greater, up to 50 percent more in 1990 as compared to 1980. Monthly requirements for 1987 for a representative pipeline illustrate the highly seasonal demand for system gas in Figure 3.

These data suggest that the pipelines, faced with sharply reduced demand for system gas, reduced committed gas supplies and, as a consequence, they will be more dependent on storage during periods of peak demand for system gas. If cold weather caused an extensive draw-down in regional storage, this would further restrict the pipelines' ability to deliver high levels of system gas.

Overall, the pipelines in the survey were extremely optimistic about the gas supply situation for the 1989-1990 winter heating season, even if extraordinarily cold weather were experienced in their service area. Over 90 percent of the companies expressed confidence in the adequacy of supplies

Table 4
Percentage Share of Pipeline Supplies (1980-1989)
(for the Months of January)

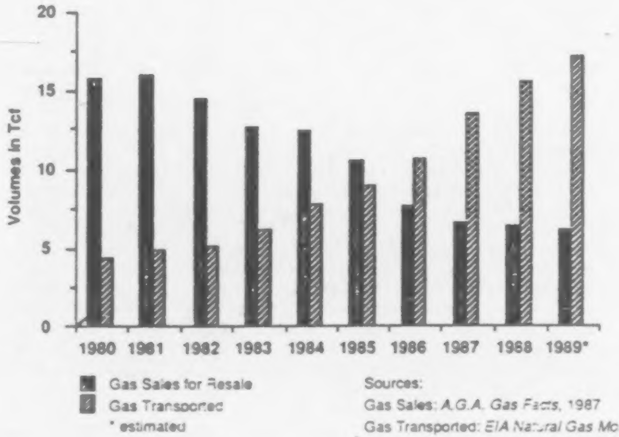
Year	System Gas	Storage	Transportation	System Supply
1980 [1]	76	19	5	100
1985 [1]	56	22	22	100
1988 [1]	42	20	38	100
1990 [2]	41	24	35	100

---

1. Actual deliveries.
2. Estimate is the maximum capability to deliver system gas in January 1990

on their systems. Some companies expected curtailments to affect non-dual fuel users if January were the coldest January in the past 50 years. In contrast, 82 percent felt that even under these extremely severe weather conditions, if any curtailments occurred, it would affect only dual-fuel customers. A distinct minority foresaw significant curtailments in a severe weather environment as likely.

Figure 2
Gas Sales and Gas Transported [1]



Sources:
Gas Sales: *A.G.A. Gas Facts*, 1987
Gas Transported: *EIA Natural Gas Monthly*
[1] Gas transported by Major Interstate Pipelines

Chapter 4

Distribution Company Trends

Over 70 local distribution companies (LDCs) responded to the A.G.A. survey. Well over ninety percent of these companies anticipated little or no difficulty in terms of adequacy of gas supplies for the coming winter heating season. Several companies were very cautious on this issue. If the winter were extremely cold, these companies anticipated significant spot market price increases and the potential for curtailment of low-priority non-dual fuel customers. Two companies that responded to the survey were quite pessimistic about their ability to handle the coldest month in 50 years without serious curtailments of non-dual fuel customers. These companies also envisioned sharp spot market price increases which would, perhaps, cause the end-users to initiate the needed curtailments.

One steadily changing aspect of the LDC gas supply programs is the steady shift away from dependence on pipeline system gas and toward independently contracted spot and longer-term gas supplies. Table 5 illustrates the change. In January 1980, survey respondents received 734 Bcf (82 percent of their total supplies) in the form of pipeline supplies of system gas. Their estimate for January 1990 is that only 586 Bcf (59 percent) would come as system gas. This January 1990 estimate is maximized because of the assumption that January 1990 would be the coldest month in 50 years and for that reason maximum supplies would be obtained from all suppliers. This decline in the use of system gas is consistent with the data reported by the pipelines regarding the rapid erosion of their system gas sales.

To counter the loss of system gas supplies, producer gas purchases (spot and longer-term) have increased from less than one Bcf in January 1980 to over 127 Bcf (13 percent of total supplies) estimated for January 1990. A lesser increase was reported for other sources of gas supply (LDC storage, including non-pipeline system supply, contract storage and owned storage, SNG, propane-air, etc.). From January 1980 (162 Bcf, 18 percent of supplies) the "other category" is expected to increase to 285 Bcf, 28 percent of supplies in January 1990.

As described earlier, the survey assumptions were formulated to create a severe stress on the gas industry in January 1990. This month was assumed to be the coldest month in the past fifty years (in each company's service area). Of special interest is, how these extreme weather conditions would alter the LDC load? Certainly there would be increased percentages of residential consumption, but how would the industrial customers fare?

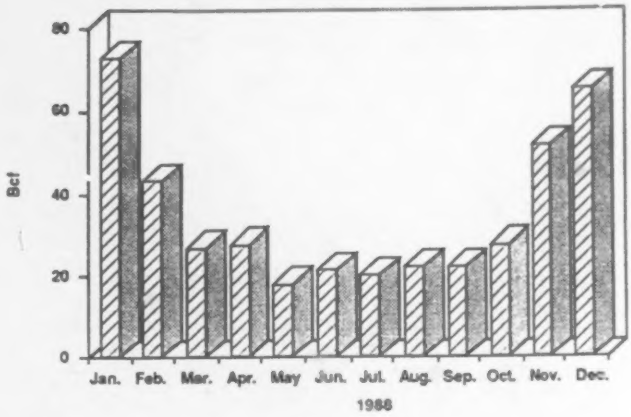
Table 6 summarizes these results. Residential and small commercial customers used 462 Bcf (60 percent of total send-out) in January 1980 rising to 518 Bcf (71 percent of total send-out) in the very cold January 1988. This group is expected to consume 571 Bcf if January 1990 has severe weather. In other words, the cold weather of January 1988 caused a 56 Bcf increase in consumption over January 1980 (518 Bcf less 462 Bcf). With the weather assumptions of the survey, demand by residential and small commercial would rise an additional 53 Bcf (571 Bcf less 518 Bcf) in January 1990. Interestingly from a percentage of total send-out viewpoint in January 1988, 71 percent was consumed by residential/small commercial customers. Under severe weather conditions assumed for January 1990 there would be no increase in the portion of total send-out going to the highest priority customers.

Table 6 also illustrates the percentages of total send-out which survey respondents attributed to the large firm/commercial industrial loads and the interruptible loads. Clearly the firm customers share of the total send-out was relatively constant at 17-22 percent. In contrast, interruptible customers would receive only nine percent of total send-out for the cold month assumed for January 1990 as compared to the more customary levels of 15-18 percent in January 1980 and 1985 or the 12 percent received in the cold (but not severely cold) January 1988.

The customers which constitute the interruptible load for the responding distribution companies have been changing their capabilities since 1980 (see Table 7). The dual-fuel customers load for 34 percent of the respondents has been increasing since 1980. This load remained about the same for 32 percent of the respondents and 34 percent reported that the dual-fuel load had decreased on their systems since 1980. There has been some speculation[5] that the dual-fuel customers would not be able to switch to alternate fuels because they had not properly maintained the equipment necessary to use the non-gas fuel. This question has been investigated in a recent A.G.A. survey. The results were that dual-fuel customers are generally capable of using alternate fuels, if needed. This survey reinforced the earlier data: 70 percent reported a high state of readiness, 29 percent were only partially ready and only one percent expressed doubts that these dual fuel customers had the capability to switch to alternate fuels.

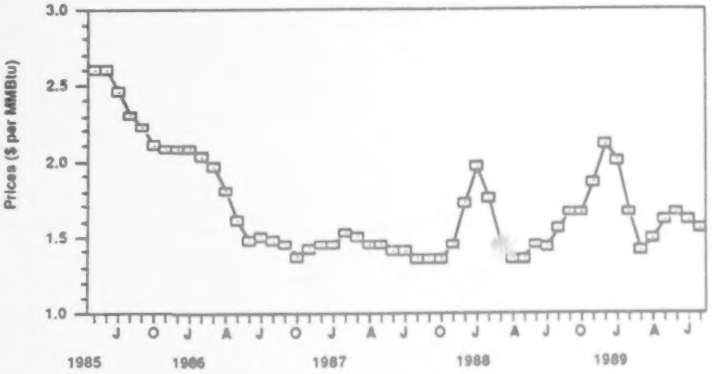
With the increased LDC dependence on spot gas there has been concern regarding the likely surge in gas prices during a severely

Figure 3
Estimated Monthly Pipeline Requirement - 1988



Source: *Natural Gas - Next Winter*, November 1988.

Figure 4
Spot Market Prices



NOTE: The values plotted are the mediam spot prices from data reported by the Natural Gas Clearinghouse.

Table 5
Percentages of LDC Gas Supplies from Different Sources 1980-1990
(for the Months of January)

Year	Pipeline System Gas	Spot Gas Purchases	Other[1]	Total
1980	82	0	1820	100
1985	78	2	23	100
1988	66	11	28	100
1990	59	13		100

---

[1] Other category includes LDC storage, non-pipeline system supply, contract and owned storage, SNG and propane-air.

cold month. The prices paid by LDC for January 1980, 1985, and 1990 (estimated) are shown in Table 8. The total spot market prices as reported by the Natural Gas Clearinghouse are displayed in Figure 4. The important result of the LDC data is that only a 4.8 percent rise over January 1988 is estimated for January 1990. The severity of the assumptions about the January 1990 temperature would cause major stresses on supply acquisitions in the spot market. Yet, only a 4.8 percent increase in the gas acquisition price is expected by the LDCs.

Table 6
Percent Share of Distribution Company Send-Out
(for the Month of January)

Year	Residential and Small Commercial	Firm, Large Commercial and Industrial	Interruptible	Total Send-Out
1980[1]	60	22	18	100
1985[1]	65	20	15	100
1988[1]	71	17	12	100
1990[2]	71	20	9	100

---

[1] January statistics.
[2] Send-out capability estimated for January 1990.

Table 7
Dual Fuel Customers as Reported by LDC

Growth of Dual-Fuel Load Since 1980	Percent of Respondents
Larger Demand in 1989	34
Demand in 1989 About the Same	32
Less Demand in 1989	34

Dual-Fuel Customers Ability to Use Alternate Fuel	Percent of Respondents
Prepared to Switch	70
Partially Prepared to Switch	29
Many are Unable to Switch	1

Table 8
Average January Price Paid for Natural Gas by LDCs
(In $ per MMBtu)

Year	Price	Percent Change Since 1980 (per year)
1980	$2.38	--
1985	$3.90	+ 10.4
1988	$2.93	+ 2.6
1990	$3.07	+ 2.6

Note: The percentage changes tabulated are annual changes; the 1990 and 1988 percentages reflect the annual growth since 1980 and are nearly equal.

Chapter 5

Major Natural Gas Producers

Natural gas supply during an extremely cold month depends on producers' ability to maintain or increase natural gas production. Most of the increased gas supply needed for the hypothesized January 1990 would be acquired through the spot market on a monthly bidding basis. For these reasons the perceptions of the major gas producers are a critical part of the evidence about the adequacy of gas supplies next winter. A number of large gas producers were asked to provide data on both their production and their contractual obligations. All specific company data provided by producers has been treated as confidential.

Respondents accounted for approximately fifteen percent of total U.S. natural gas production in 1988.[6] Based on data reported in other studies the information reported in Table 8, while not comprehensive, is representative of major oil and gas companies which are large natural gas producers.[7]

Probably the most significant aspect of change in the past decade among the major producing companies has been their strong entry into natural gas sales. This sales effort on the part of the producers was in part due to the excess production capability (the "bubble")[8] and in part to the pipeline shedding of gas reserves. Table 9 shows that committed gas sales in January 1980 were 98 percent of sales but by January 1990, only 49 percent of gas sales will be to customers who have long term commitments from the producers. As the pipelines reduced their volumes of committed gas to lower their take-or-pay contractual obligations, the producers acquired more gas that was available for short term/spot market sales. The larger short term gas supplies served to introduce a seasonal volatility in gas prices which had not been observed in the natural gas market in earlier years. Furthermore, as can be seen in Table 10, the producers expect to be direct sellers to LDC and end-users for 79 percent of their gas sales for January 1990.

Similar to the survey questions to pipelines and LDCs, the producers were asked to share their expectations regarding gas supply for January 1990, assuming that this month would be the coldest month in the past fifty years in the areas in which their gas is normally consumed. As was the case for the other segments of the industry, there was a general feeling that gas supplies were adequate for all firm customers to be served. Interruptible customers were likely to be interrupted during a severely cold month (as the hypothesized January 1990) and spot market prices would rise as they have for the past several years. This perception is essentially in agreement with earlier gas industry reports[1] and the current expectations of most pipelines and LDCs.

Table 9
Percentages of Producer January Sales of Natural Gas
1980-1990

Year	Committed Gas Sales	Spot Gas Sales
1980	98	2
1985	84	16
1988	52	48
1990	49	51

Table 10
Percentage of Producer Gas Sales By Purchaser
1980-1990
(for the Month of January)

	Percentage Purchased By		
Year	Pipelines	LDC	End-Users
1980	75	1	24
1985	78	1	21
1988	52	10	38
1990	21	25	54

Footnotes

[1] *Natural Gas - Next Winter*, A Report of the A.G.A. Gas Supply Committee, November 1988.

[2] *Executive Gas Industry Statistics*, August 1989.

[3] *Natural Gas Deliverability Study - Final Report*, Interstate Oil Compact Commission, December 1984.

[4] *Gas Energy Review*, August 1988.

[5] Joint communcation by G.H. Lawrence and J.C. Sawhill titled, *Where We Are*, July 12, 1989.

[6] *Preliminary Findings Concerning 1988 Natural Gas Reserves*, A.G.A. EA 1989-9, April 1989.

[7] *The Changing Role of Natural Gas in the Major Oil Companies*, A.G.A. EA 1989-9, September 1989.

[8] *Natural Gas Production Capability - 1989-1990*, A.G.A. IB 1989-12, July 1989.

APPENDIX I
NATURAL GAS UNDERGROUND STORAGE
(in Bcf)

		Natural Gas in Underground Storage, End of Period		
		Base Case	Working Gas	Total
1973	Total	2,864	2,034	4,898
1974	Total	2,912	2.050	4,962
1975	Total	3,162	2,212	5,374
1976	Total	3,323	1,926	5,250
1977	Total	3,391	2,475	5,866
1978	Total	3,473	2,547	6,020
1979	Total	3,553	2,753	6,306
1980	Total	3,642	2,655	6,297
1981	Total	3,752	2,817	6,569
1982	Total	3,808	3,071	6,879
1983	Total	3,847	2,595	6,442
1984	Total	3,830	2,876	6,706
1985	Total	3,842	2,607	6,448
1986	Total	3,819	2,749	6,567
1987	January	3,818	2,280	6,098
	February	3,815	1,988	5.803
	March	3,813	1,879	5,693
	April	3,812	1,938	5,750
	May	3,811	2,206	6,017
	June	3,810	2,437	6,247
	July	3,813	2,636	6,449
	August	3,813	2,836	6,648
	September	3,813	3,049	6,862
	October	3,813	3,106	6,919
	November	3,792	3,059	6,851
	December	3,792	2,756	6,548
1988	January	3,792	2,229	6,021
	February	3,791	1,827	5,618
	March	3,790	1,684	5,474
	April	3,790	1,770	5,560
	May	3,790	2,028	5,818
	June	3,792	2,293	6,085
	July	3,793	2,567	6,359
	August	3,791	2,834	6,625
	September	3,791	3,121	6,912
	October	3,792	3,243	7,035
	November	3,803	3,197	6,999
	December	3,800	2,871	6,672
1989	January	3,800	2,520	6,320
	February	3,798	2,000	5,798
	March	3,798	1,774	5,572
	April	3,792	1,825	5,617
	May	3,798	2,058	5,856

Total underground storage capacity at the end of each calendar year (in billion cubic feet): 1978-6,890; 1979-6,329; 1980-7,434; 1981-7,805; 1982-7,915; 1983-7,985; 1984-8,043; 1985-8,087; 1986-8,145; 1987-8,124; and 1988-8,124. Current capacity is 8,124

Notes: Geographic coverage is the 50 States and the District of Columbia. Totals may not equal sum of components due to independent rounding. Data through 1987 are final. Subsequent data are preliminary.

Source: EIA. *Monthly Energy Review*. April 1989.

PEAK MONTH GAS SUPPLY - DEMAND -1990
in Bcf

Supply Capability	
Conventional Production	1600
Storage Withdrawal	700
Canadian Gas	150
LNG, SNG, Exports,Storage, Injections	(6)
TOTAL	2444
Maximum Monthly Consumption 1/79	2426

Maximum Monthly Gas Supplies and Consumption, 1973 through January 1989 (in Bcf)

Year	Production[1]	Domestic Supplementary Gas[2]	Imports[3]	Storage Withdrawal[4]	Consumption[5]
1981	1684	20	93	571	2279
1982	1657	19	110	697	2400
1983	1530	17	112	634	2191
1984	1629	17	97	563	2219
1985	1559	13	106	661	2148
1986	1536	12	99	421	2106
1987	1533	11	121	521	2051
1988	1535	17	138	576	2168
1989[6]	1503	16	119	397	2008

---

[1] Dry gas production

[2] Includes SNG from liquid hydrocarbons, propane-air, LNG storage, landfill gas, coke oven gas.

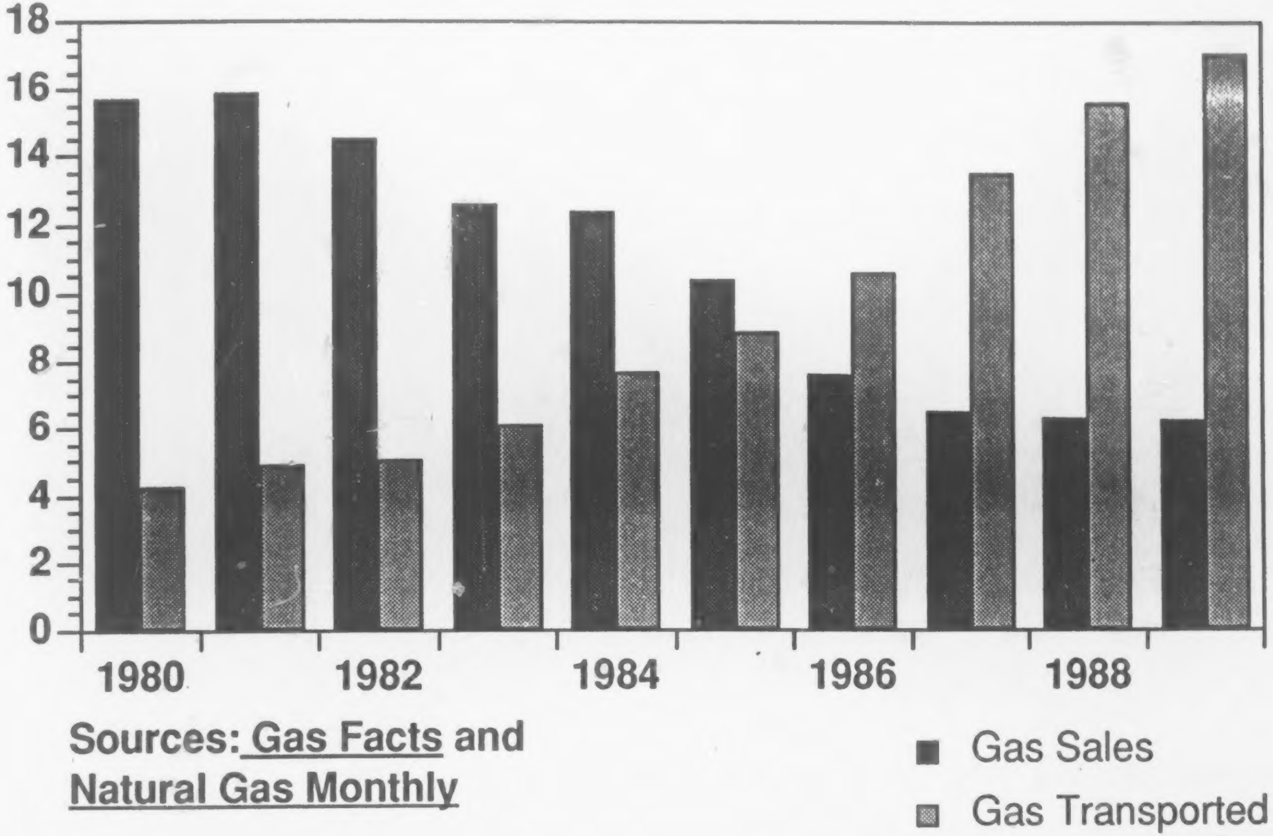
[3] Canadian Gas and LNG imports.

[4] Underground storage withdrawals.

[5] As reported by EIA.

[6] January - May only.

INTERSTATE GAS SALES AND GAS TRANSPORTED



Sources: Gas Facts and Natural Gas Monthly

Demonstrated Natural Gas Production In Peak Months

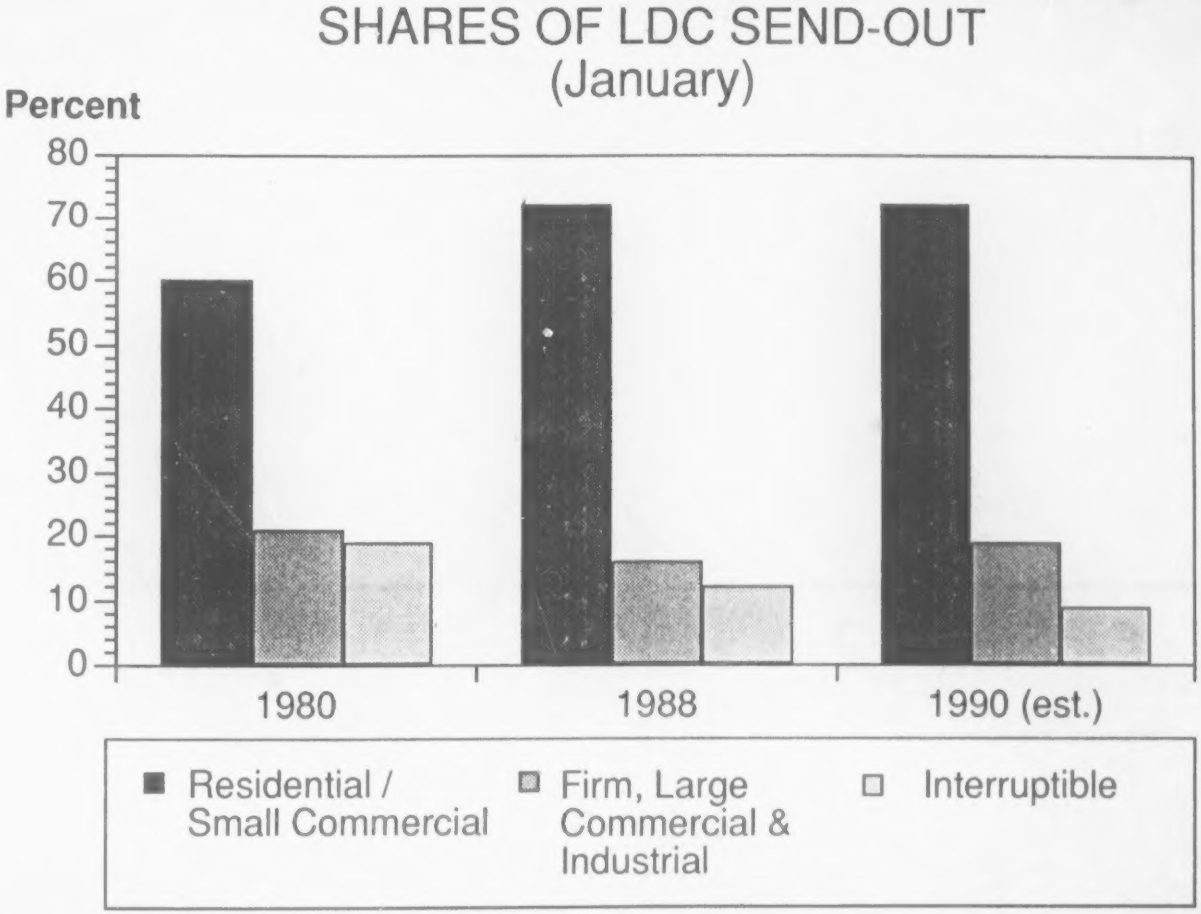
	Ratios				
	1985	1986	1987	1988	1989
State	1980	1980	1980	1980	1980
Kansas	.671	.582	.590	.596	.491
Louisiana	.809	.773	.739	.738	.739
New Mexico	.943	.725	.840	.817	.764
Oklahoma	.969	.907	.921	.884	.926
Texas	.908	.895	.913	.909	.872
Wyoming	1.037	1.148	1.292	1.515	1.718
U.S.	.898	.882	.878	.879	.884

*in MMCF

Source: EIA, *Natural Gas Monthly*, April 1989

PERCENTAGE OF PRODUCER GAS SALES BY PURCHASER

Year	Pipelines	LDC	End-Users
1980	75	1	24
1985	78	1	21
1988	52	10	38
1990	21	25	54



SHARES OF LDC SEND-OUT
(January)

Incremental Short-Term Gas Supply Potential
(Bcf)

	Within 12 Months	Within Three Years
Nonproducing Reserves	250-750	500-1,000
Canadian Gas[1]	400	500
Accelerated Infill Drilling	50-100	100-400
Liquefied Natural Gas[2]	40-100	200
Total Additional Supply Available	700-1,350	1,300-2,100

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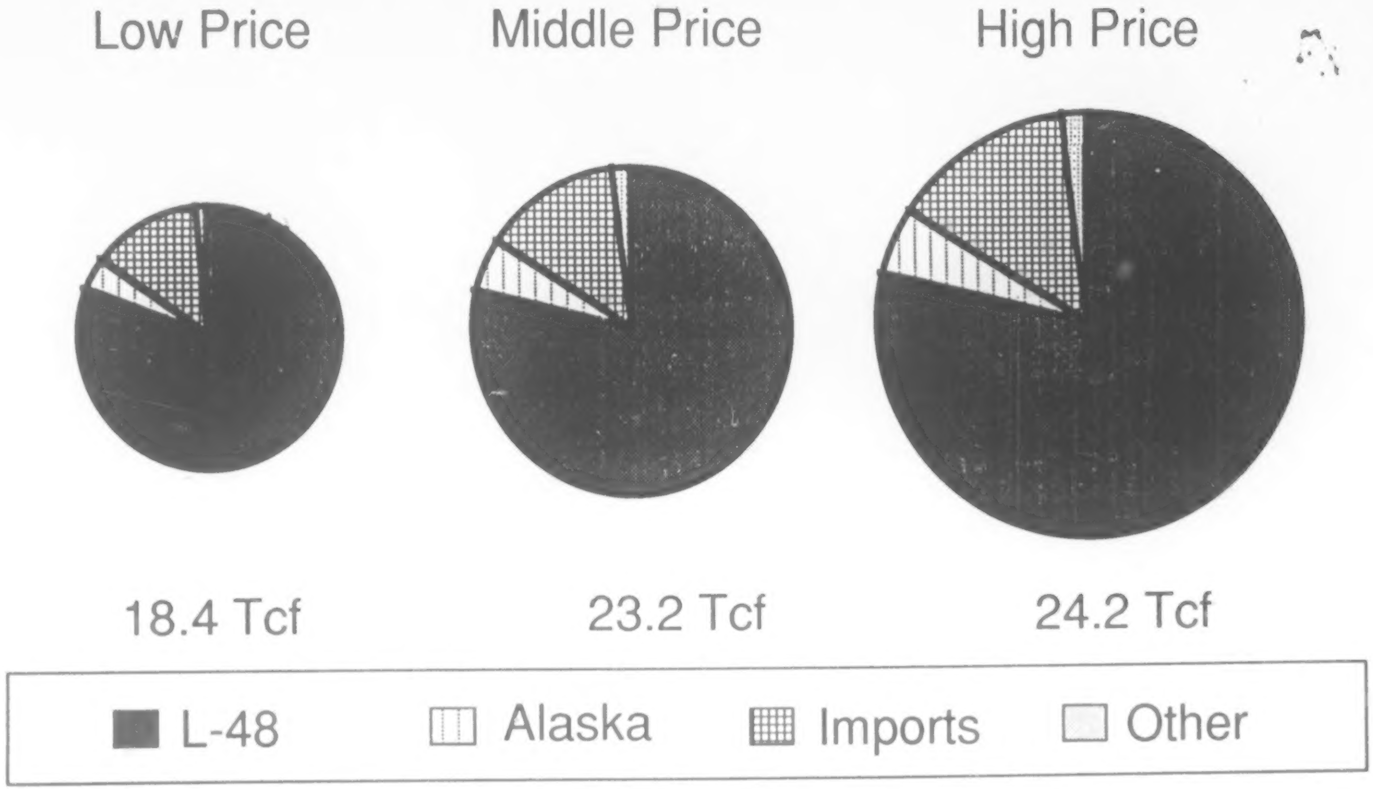
[1] Volumes are in addition to the 1,283 Bcf estimated from Canada in 1988.

[2] Volumes are well below the physical limitations of the existing terminals.

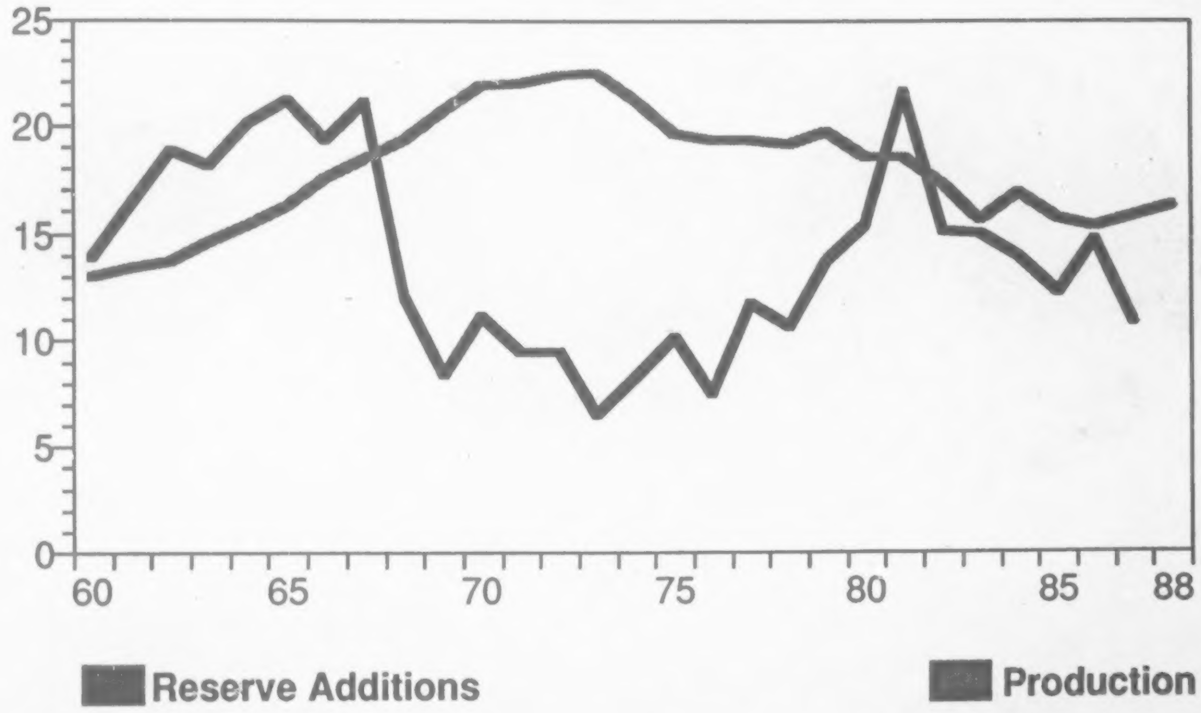
LOWER-48 PRODUCTION CAPABILITY

	1995	2000	2010
LOW PRICE	$ 18	$ 22	$ 33
Production	15.0	15.0	15.0
MEDIUM PRICE	$ 20	$ 27	$40
Production	16.9	18.0	18.5
HIGH PRICE	$ 30	$ 38	$ 62
Production	17.5	18.8	19.5

NATURAL GAS SUPPLIES 2010



LOWER-48 NATURAL GAS PRODUCTION VS. RESERVE ADDITIONS 1960 -1988



CONCLUSIONS

- **Adequate gas supplies**
- **Strong price incentives could increase supplies**
- **Gas can provide 20 - 25 percent of U.S. energy needs**
- **Gas will be: more than 86% domestic**
  less than 4% from overseas

APPENDIX II

Additional Material Submitted for the Record

Oil to Gas Ratios – Revenues

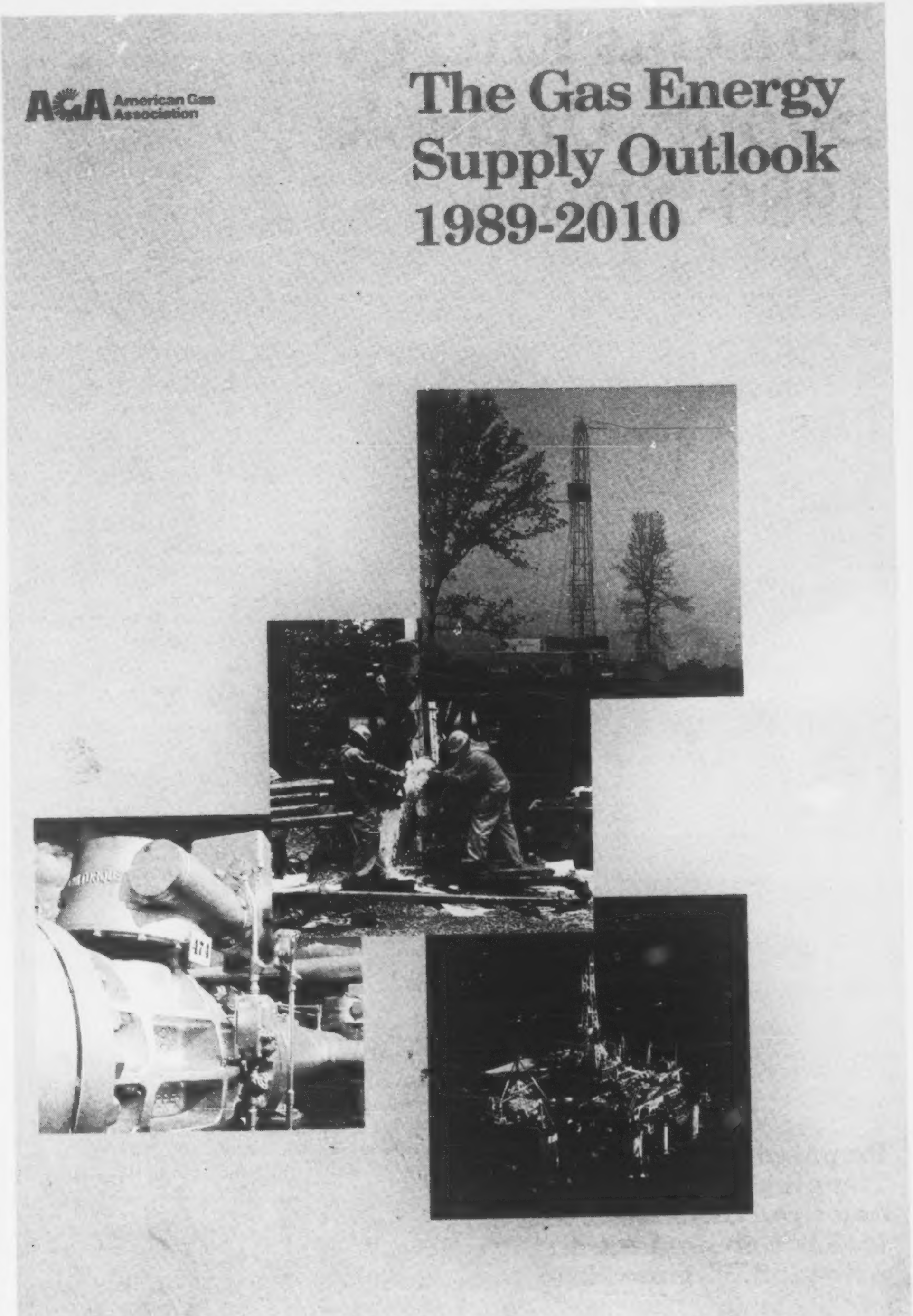
	1984	1988
BP America	28.70	16.9
Arco	3.39	2.46
Exxon	3.16	2.31
Shell	2.94	2.14
ORYX	2.70	2.14
Chevron	2.82	2.13
Texaco	2.53	1.82
Amoco	1.66	1.72
USX	2.11	1.54
Unocal	1.99	1.42
Phillips	2.35	1.13
Mobil	1.92	1.11

Differential Between Producer Selling Price and National WHP

	1984	1986	1988
BP America	+.01	-.36	-.01
Arco	-.08	0	-.03
Exxon	-.50	+.07	+.09
Shell	+.14	+.23	+.18
ORYX	-.16	-.13	-.12
Chevron	-.31	-.25	-.31
Texaco	-.44	-.08	+.01
Amoco	+.27	+.05	+.16
USX	-.09	-.20	-.14
Unocal	-.37	0	+.10
Phillips	-.72	-.30	-.18
Mobil	-.23	+.02	+.18

Concentration of Ownership – Reserves and Production
(As a percent of the total U.S.)

Reserves				Production			
Oil		Gas		Oil		Gas	
1983	1988	1983	1988	1983	1988	1983	1988
50.2	55.3	36.6	41.7	56.4	65.6	33.8	35.5



AGA American Gas Association

The Gas Energy Supply Outlook 1989-2010

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A Report of the A.G.A.
Gas Supply Committee

Prepared by the
Planning and Analysis Group
American Gas Association
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Executive Digest

Natural gas supplies should be ample to meet current consumption levels under all likely gas price scenarios throughout the period 1989-2010. At a maximum, potential supply capability could increase to 24.2 Tcf or 10 percent over peak annual U.S. consumption levels experienced in the early 1970s. This evaluation of gas supply anticipates a free market for gas in the field.

The following table presents a summary of the Committee's gas supply estimates. Also shown are the shares of total supply accounted for by the domestic lower-48 sources which include conventional gas production, gas from tight formations and coal seams, enhanced gas recovery (including co-production of gas and brine), synthetic gas and a variety of nonconventional sources. It is important to understand that these are estimates of potential supply capability without regard to specific gas demand constraints. That is, the derived estimates are the aggregate U.S. volumes that one could expect to be made available at three different hypothesized prices. The study makes no judgement about which (if any) price scenario might be the most likely to occur.

In each price scenario about 85% of total supply comes from lower-48 sources in 2000. By 2010, lower-48 sources are projected to decline as a percentage of total supplies but still are expected to represent approximately 80%. The remainder is made up from a variety of sources including imports from Canada, Mexico, overseas (as LNG) and gas from Alaska. Hence, U.S. natural gas supplies continue to be primarily of North American origin and thus are not likely to be adversely affected by international political actions.

As indicated by the Committee's forecasts, the outlook for gas supply is excellent. For a wide range of future energy price scenarios, supplies should be adequate to meet, not only existing requirements, but substantial market growth exceeding the current gas market share of approximately 25% of U.S. energy consumption.

Since the mid-1970s, a key element in national energy planning has been the future outlook for the supply of natural gas. In this report, the A.G.A. Gas Supply Committee examines the gas resource base, technological developments that will affect future gas production and the diversity of potential supply sources that contribute to the overall gas supply outlook. These factors, when combined with the one million-mile U.S. gas delivery system, provide the basis for a favorable gas supply outlook. This biennial report, the sixth in a series dating back to 1980, discusses the many present and future sources of natural gas supply and presents the Committee's estimates for potential future gas supply capability.

The estimates have been developed using three scenarios based on differing crude oil and natural gas prices. The Low Price Scenario assumes a small rise in the world oil price to $18 per barrel by 1995 at which time a four percent real growth begins and continues through 2010. The Middle Price Scenario assumes minor real oil price growth to 1995 and then escalation at a 4.7 percent real growth rate through 2010. The High Price Scenario envisions an environment in which more rapid crude oil price growth occurs, with escalation to $30/bbl (1988$) in 1995 and then a five percent real growth rate through 2010. Natural gas prices for the three scenarios were developed from postulated relationships with the oil prices and assumed escalation of oil prices was based on rates developed by the National Petroleum Council (NPC) in their 1987 study.

Future U.S. Annual Natural Gas Supply Capability
(Tcf)

	Oil Price ($1988/bbl)	1995	2000	2010
Low Price Scenario	18-22-33	17.0	17.4	18.4
Middle Price Scenario	20-27-40	19.2	21.5	23.2
High Price Scenario	30-38-62	19.9	23.0	24.2
Lower-48 Sources* Share		88-89%	82-87%	80-82%

* Lower-48 Sources include conventional natural gas including natural gas from tight formations, coal seams and co-production; synthetic gas and nonconventional sources.

Section I

Executive Summary

Background

Biennially the A.G.A. Gas Supply Committee updates its assessments of the future potential for conventional and supplemental production of natural gas. The discussion and estimates in this report present a consensus view of the Committee (which represents the gas transmission and distribution industry). The Committee is composed of senior-level executives who are active on gas supply issues within their respective companies and who have had extensive advice from the gas-producing industry. The companies which participate on the Committee represent a broad cross-section of the gas utility industry.

This report updates previous Committee reports published in 1980, 1982, 1983, 1985 and 1987. The Committee's new assessment does not represent major changes in gas energy resource potential from the 1987 study; rather, it is a re-evaluation of the future price-sensitivity of gas energy supply within an environment characterized by transition of the gas industry to less regulation, increased marketplace competition, and a recognition of potential emerging technologies. Thus, there are several factors that are critical in assessing the supply capability.

- *Dissipation of the gas "bubble"*—An excess gas deliverability ("a bubble") has persisted through the 1980s, and it has been a key factor in limiting drilling activity. The small, remaining excess production capability is expected to decline. The subsequent response to the end of the "bubble" in exploration and production activity is an important factor in determining future supply during the early 1990s. This in turn will impact the rate of resource development throughout the time period covered by this report.
- *Gas price outlook*—As the excess gas deliverability "bubble" dissipates, gas prices are expected to rise, leading to increased exploration. However, such increases are not expected to be sharp, due to the available gas cushion of reserves and exploration prospects in both the U.S. and Canada. The extent to which gas prices (and oil prices) grow through 2010 will heavily impact upon the availability of gas from the sources discussed in this report.
- *Oil Price Outlook*—Oil prices will also impact the availability of gas. Associated gas accounts for 30% of total U.S. proven reserves and over the 1985 to 1987 period associated gas reserve additions averaged 19% of total U.S. gas reserve additions. Oil prices are important not only because of their impact on the production of associated gas but also because of the oil directed drilling that results in gas reserve additions through "accidental" discoveries when gas is found when the target was thought to be oil.
- *Technological advances*—Gas Research Institute (GRI) and other research program successes in developing processes such as means for recovering gas from tight formations, as well as exploration advances by producers and service companies, have led to new judgments about the economic viability of some resources. For example, gas reserves at water depths greater than 1,000 meters in the Gulf of Mexico are resources which only a few years ago were thought to be technologically inaccessible but are now considered feasible at certain prices.

The Committee's analysis, which involved a supply capability forecast without regard to specific gas demand constraints, included the following two major elements:

- *Lower-48 states natural gas supply*—Analyses of the potential conventional natural gas resource base, and the effect of varying levels of exploration and production activity, served as inputs to the estimation of production levels from conventional sources. Before reaching its conclusions, the Committee also considered the assumptions and conclusions of leading government and private sector quantitative and qualitative forecasts of gas supply. The analyses of conventional gas sources included production from tight formations, coal seams and enhanced recovery techniques (including co-production of gas and brine from older fields), many of which are currently commercially producible. Other sources such as the gasification of other hydrocarbons, methane from landfills and biomass gas are also included as part of the lower-48 production potential.
- *Other sources of gas supply*—Separate detailed analyses which included economic, technical and institutional considerations were conducted for many different producing and potential sources of gas energy other than the contiguous lower-48 states. Included are domestic sources such as gas from Alaska, as well as imports from Canada and Mexico by pipeline, and overseas sources in the form of liquefied natural gas (LNG).

Methodology

The methodology used by the Committee to forecast production volumes is based on the integration of gas supply studies made by a variety of sources, including individual Committee member companies. These specialized company estimates each have particular areas of expertise which serve as the foundation for the new Gas Supply Committee estimates. The economic assumptions used in these independent analyses reflect three pricing scenarios—a low energy price, a middle energy price and a high energy price. Comparison and discussion of the individual A.G.A. member company estimates, analysis from other sources and special studies by A.G.A. permitted the development of estimates of production volumes which might be available at a particular price in a given year. These estimates were then subjected to a variety of tests for reasonableness by the Committee members in order to arrive at the consensus values which are presented and described in this report.

This assessment of supply is consistent with the economics definition of a supply function, that is, gas volumes that would be made available at different prices, without regard for natural gas demand or consumption in individual market sectors. Interfuel competition, fuel switching, economic conditions, weather and technological innovations are key factors in determining if a free market will actually demand the volumes of natural gas which can be made available in the future at various postulated prices. Representative separate and independent gas demand analyses have been conducted by the A.G.A. Gas Demand Committee. The most recent such report, published in 1989, will be titled "The Gas Energy Demand Outlook: 1989-2010."

Results

The major conclusions of this updated study regarding gas supply available at different prices in the year 2010 are:

- Overall, sufficient gas energy supplies are likely to be available to continue to supply at least 20-25 percent of the nation's total need for energy.
- Although projected volumes of gas supply in 2010 vary with assumptions about future technical and energy price conditions, it is estimated that between 18.4 and 24.2 trillion cubic feet (Tcf) per year of conventional and supplemental gas supplies should be available.
- The availability of sufficient supplies to meet annual gas requirements does not guarantee deliverability to all customers in all regions during peak periods. It is possible, even likely, that at some time "best efforts" customers will experience interruptions during peak requirements due mostly to infrastructural limitations in the gas industry such as pipeline capacity in certain regions and fluctuating customer-pipeline system requirements.

In general, the outlook is favorable for gas supply during the next 20 years. The transportation system for gas is flexible and capable of delivering amounts of energy above those now delivered throughout the nation; has over one million miles of underground pipeline in place; is environmentally benign, cost competitive and efficient; and includes a large (a demonstrated 3.2 Tcf of annual working gas) seasonal gas storage capability. Even under the most unusual weather conditions, most gas distribution and transmission companies should be able to handle transitory increases in gas demand.

Lower-48 States

Lower-48 states gas production is currently, and will continue to be, our nation's most important source of gas into the next century. The lower-48 states' section in this report identifies future supplies anticipated from both conventional formations as well as new sources made accessible by new technological advances.

The Potential Gas Committee estimates recoverable conventional lower-48 states natural gas to be 831 Tcf, including proved reserves. These resources exclude most lower-48 tight formations, coal seams, enhanced gas recovery and nonconventional resources which require new technological advances for economic development.

Other Sources of Gas Supply

Other supplemental sources of gas (i.e., sources other than lower-48 production) currently provide less than 10 percent of the total U.S. natural gas supply. However, this percentage is likely to increase over the next 25 years, so that by the year 2010, sources other than lower-48 supplies are expected to contribute from 18 to 20 percent of the total gas supply.

Pipeline deliveries from Canada are likely to be the dominant supplemental supply source. Other imports, such as gas from Mexico and LNG are expected to contribute less than one Tcf to total U.S. supply through 2010. In addition, domestic gas resources such as natural gas from Alaska could be of significance after the turn of the century.

It is expected that all of these supplemental sources would contribute to the nation's future gas supply. However, changes in gas market conditions (particularly prices), national energy priorities and policies, and technological advancements will impact the rate at which each of these sources is integrated with lower-48 states supplies.

Scenarios

In an attempt to understand the dynamics of the various supply sources under widely varying economic conditions, the Committee developed its estimates for three different pricing scenarios (see Tables I-1, I-2 and I-3). None of these scenarios is intended as a "best guess" or is considered by the Committee as a most likely estimate of the future. Instead, the scenarios are used to demonstrate how the different sources of gas supply might respond to different energy price levels. Because a diversity of economic, technical and regulatory issues surrounds each of the various supply sources, it is useful to understand how the supply capability of each source might differ from one scenario to the next.

The three scenarios developed by the Committee are the Low Price Scenario, the Middle Price Scenario and the High Price Scenario. The Committee believes that these three cases represent a pricing spectrum broad enough to both reflect plausible future prices and to illustrate the price-sensitive supply responses of the different sources of gas.

The Low Price Scenario assumes relatively flat oil prices in 1988 real dollars to the year 1995 at which time the oil price would be $18 per barrel (bbl). Beyond 1995, there is a steady 4% annual rise in oil prices, reaching $33/bbl (1988$) in 2010. The gas price associated with the $33/bbl oil price in 2010 is $4.84 per million British Thermal Units (MMBtu), almost three times the average wellhead price in 1988. This scenario assumes that cooperation among OPEC cartel members is ineffectual, so that oil production levels relative to demand result in continued surplus supplies—a continuation of the situation which prevailed over the past few years. Competition between natural gas and residual fuel oil continues to influence gas prices. This results in little additional incentive to develop new gas resources over the period and thus results in the lowest gas supply estimate.

The Middle Price Scenario assumes a more rapid growth rate in oil and gas prices in real terms. This growth begins in 1989 and results in oil and gas prices respectively, of $27/bbl and $3.63/MMBtu in 2000, and at $40/bbl and $5.52/MMBtu in 2010. In this scenario world oil prices rise as increased oil demand reduces the world surplus of oil. Oil supply and demand levels are such that prices increase at an average real rate of 4.7 percent per year. The increasing energy prices provide additional incentive for the development of new gas supply sources. Thus, this scenario results in a higher gas supply response than the Low Price Scenario.

The High Price Scenario results in the highest oil and gas price levels and thus increases the economic incentive to develop a full array of gas supply sources. Under this scenario, the OPEC cartel is able to achieve a rapid escalation in oil prices. Thus, oil and gas prices rise to levels not unlike those anticipated by many studies in the early 1980s. By the year 2000, oil prices will have reached $38/bbl, with gas prices at $4.59/MMBtu. By 2010, oil prices increase to $62/bbl and gas prices reach $7.48/MMBtu (in 1988$). These prices result in the highest level of domestic gas supply availability, a result that would have especially important implications in minimizing the instability associated with imports of expensive foreign oil.

Observations from the estimates presented under the three scenarios are:

- Available gas supply for the year 2010 should be, in all cases, at least 18.4 Tcf, compared to the 1988 actual consumption of 17.7 Tcf.
- The gas supply estimates for the year 2010 should be between 18.4 and 24.2 Tcf depending upon the pricing scenario. The 24.2 Tcf level represents a 37 percent increase over the 1988 level of actual gas supply.
- Average available supply for the three scenarios for the year 2010 is 21.9 Tcf per year, constituting an increase of 24 percent over the 1988 level of actual gas supply.
- Foreign overseas sources of LNG generally account for less than 4 percent of the total supply in all scenarios. All imports, including those from Canada and Mexico, range between 11 and 14 percent of the total supply in the various scenarios.
- Sources of gas supply in the future should be more diverse and will tend to change depending on economic and technological development.
- Each scenario leads to a different configuration of sources in the gas supply forecast. In all cases supply was adequate for gas to maintain at least a 20 to 25 percent share of the total national energy requirement. At the upper end of the range of supplies there appears to be sufficient available resource to increase supplies, if dictated by energy prices, to levels as high as 24.2 Tcf.

Low Price Scenario

The Low Price Scenario results in the lowest estimate of future available gas supply (see Table I-1). At the prices in this scenario, efforts to develop the conventional gas resource proceed at relatively low levels, with only the most promising prospects being explored and drilled. Thus, lower-48 conventional gas production levels decline from 16.3 Tcf in 1988 to 15 Tcf by the year 1995 and remain constant at that level. Projects to develop supplemental gas supplies (excluding pipeline imports) are undertaken late in the period once prices have reached the levels required for the economic viability of these projects. However, with the exception of pipeline imports, LNG and Alaskan pipeline supplies, the supplemental gas sources produce 100 Bcf annually throughout the forecast period. Imports from Canada are limited to 1.8 Tcf/year between 2000 and 2010 because relatively low prices limit the rate of development of Canadian frontier resources and pipeline delivery systems. In this scenario, U.S. markets compete with growing Canadian demand for conventional Canadian gas production. Gas exports from Mexico resume before 2000 and continue through the year 2010. This is because of Mexico's need for additional revenue in an environment of low oil prices. Additionally, the lower level of conventional U.S. production generally increases the demand for imported gas. Total supply capability in 2010 under this scenario is nearly the same as the 1988 production levels. For the forecasted periods, the gas availability varies from 17.0 Tcf in 1995 to 17.4 Tcf in 2000 and then rises to 18.4 Tcf in 2010. More specifically, major features of the Low Price Scenario include:

- a very slow rebound in domestic gas drilling, resulting in a decline in production capability;
- Canadian import contract renewals at currently authorized levels, with competitively priced additional quantities of pipeline imports to supplement lower supply volumes from other sources;
- Mexican imports being resumed reflecting the desire of the Mexicans to sell more gas to offset the loss of income as a result of low world oil prices;

TABLE I-1

Gas Supply—Low Price Scenario

(Tcf)

	1988 Actual Supply	Available Supply		
		1995	2000	2010
Oil Price Assumption ($1988/bbl)	$14.76	$18.00	$22.00	$33.00
Gas Price Assumption ($1988/MMBtu)	$ 1.71	$ 2.33	$ 3.03	$ 4.84
Lower-48*	16.3	15.0	15.0	15.0
Imports				
Canadian	1.3	1.7	1.8	1.8
Mexican	—	—	0.1	0.1
LNG	**	0.2	0.4	0.6
Alaskan Gas Pipeline	—	—	—	0.8
Other Supplemental Sources	0.1	0.1	0.1	0.1
Totals (rounded)	17.7	17.0	17.4	18.4

* Lower-48 Production includes gas from tight formations, coal seams, and co-production.

** Less than 25 Bcf.

Note: See Table IX-1 for more detail.

- reluctance to build additional LNG facilities but a steady increase in the utilization of established terminals;
- delayed development of Alaskan resources with no deliveries to the lower-48 states until after the turn of the century;
- continued operation of the Great Plains Coal Gasification Project but no new coal gasification projects;
- low overall activity in gas exploration and development that slows the application of new technologies for production from marginal conventional resources in the lower-48 states.

Middle Price Scenario

The Middle Price Scenario results in an intermediate level of gas supply availability (See Table I-2), since all but the most expensive gas supply options reach an advanced stage of development. Application of new technologies leading to increased lower-48 gas production is significant with noticeable gains by 2000. World crude oil prices and domestic gas prices are such that a large part of the conventional resource and a moderate number of projects to develop Alaskan and nonconventional sources are economically viable. The increase in lower-48 conventional production between 1995 and 2000 is accentuated by increased LNG and Canadian imports. By 2010, lower-48 sources account for 18.5 Tcf of annual production capability. This increase is brought about principally by rapid technological advances such as those associated with seismic techniques and deepwater completions. Alaskan gas becomes available before 2000 with the construction of a pipeline system to deliver those supplies. Gas from nonconventional sources becomes more economically viable towards the end of the forecast period with about 100 Bcf of gas available annually by 2000. Gas imports are available in this scenario with rates of growth varying among the sources. Canadian imports are higher than in the Low Price Scenario since higher prices contribute to the development of the Canadian frontier areas and thus open up a substantial gas resource to U.S. markets. Mexican imports are not available because of Mexico's reluctance to export gas versus oil in a higher oil price environment. In this case, a heightened effort is made to displace oil use with gas within the Mexican economy. Regarding LNG imports, no new facility construction is undertaken; however, increased use of existing facilities becomes economically feasible.

By 2010, total supply capability under the Middle Price Scenario increases to about 31% over the 1988 consumption level of 17.7 Tcf. More than half of this growth is achieved prior to the end of the century with the total available supply reaching 21.5 Tcf by 2000. By 2010, supply capability reaches 23.2 Tcf, of which 81% is provided by the lower-48 supply sources. Some of the more specific features include:

- a more rapid rise in gas prices results in a turnaround in drilling and an improved production capability;
- development of the Canadian frontier areas such that additional pipeline projects are built and significant parts of the large frontier resource become available to U.S. markets;
- Mexican federal government actions would be guided primarily by maximizing oil exports resulting in termination of gas exports;
- regulatory neutrality on increased use of existing LNG facilities;
- development of Alaskan resources consistent with the ability to sell the gas at competitive market prices;
- significant near-term application of advanced technologies leading to increased lower-48 production capability.

TABLE I-2

Gas Supply — Middle Price Scenario

(Tcf)

	1988 Actual Supply	Available Supply		
		1995	2000	2010
Oil Price Assumption ($1988/bbl)	$14.76	$20.00	$27.00	$40.00
Gas Price Assumption ($1988/MMBtu)	$ 1.71	$ 2.59	$ 3.63	$ 5.52
Lower-48*	16.3	16.9	18.0	18.5
Imports				
Canadian	1.3	1.8	2.0	2.5
Mexican	—	—	—	—
LNG	**	0.4	0.6	0.8
Alaskan Gas Pipeline	—	—	0.8	1.2
Other Supplemental Sources	0.1	0.1	0.1	0.2
Totals (rounded)	17.7	19.2	21.5	23.2

* Lower-48 Production includes gas from tight formations, coal seams, and co-production.

** Less than 25 Bcf.

Note: See Table IX-2 for more detail.

High Price Scenario

The High Price Scenario results in the highest level of available gas supply and represents a maximum capability of the industry under strong economic stimuli. In this scenario, a rapid escalation of fuel prices results in accelerated development of the conventional resource. Compared to the 1988 actual production level of 16.3 Tcf, the lower-48 conventional production capability increases to the level of 18.8 Tcf by 2000 and by 2010 reaches 19.5 Tcf. This vigorous development occurs early in the period such that the most prolific gas resources are developed in the 1995-2000 time frame. Application of new technologies leading to increased lower-48 gas production capability is significant in the near-term. The high prices accelerate the penetration of advanced technologies into industry practice. As these resources are developed and produced, traditional production capability begins to decline and resources requiring longer lead-times are brought on line. As in the Middle Price Scenario, the relative amounts of imports vary with the source. Canadian imports reach the 2.5 Tcf level by 2010 as frontier areas are developed. Imports are limited to 2.5 Tcf because domestic Canadian gas demand increases to displace expensive oil. Mexican imports are not re-established in this scenario since all Mexican production is used internally to enable increased exports of high-priced oil. LNG imports through current facilities are competitive in the early 1990s but new facilities are not constructed. Nevertheless, price incentives encourage increased LNG imports through 2000 at which time imports could be as high as 0.8 Tcf per year. Projects to bring Alaskan gas to the lower-48 states are viable in the late 1990s and 1.2 Tcf is transported to lower-48 markets by 2000. Synthetic gas begins to be produced before the end of the forecast period. Likewise, extremely high prices at the end of the period stimulate a variety of nonconventional gas production projects such that by 2000, approximately 200 Bcf is produced annually.

Total supply availability under the High Price Scenario reaches 24.2 Tcf by the year 2010. This represents a production capability over one-third more than actual production in 1988. In contrast to the other price scenarios, gas and oil prices increase at much greater rates, with oil prices 4 times higher and gas prices almost 5 times higher than their respective 1988 levels. More specifically, features of this scenario include:

- rapid and extensive development of domestic gas resources;
- development of Canadian frontier areas such that additional pipeline projects are built, and supplies from the large frontier resource become available to U.S. markets;
- accelerated technology development for tight gas resources, coal seams and co-production to supplement declining traditional production levels;
- no gas exports from Mexico as Mexican revenue requirements are met by the export of higher-valued oil products;
- vigorous development of Alaskan resources and construction of an Alaskan pipeline;
- full use of existing LNG facilities.

TABLE I-3

Gas Supply—High Price Scenario

(Tcf)

	1988 Actual Supply	Available Supply		
		1995	2000	2010
Oil Price Assumption ($1988/bbl)	$14.76	$30.00	$38.00	$62.00
Gas Price Assumption ($1988/MMBtu)	$ 1.71	$ 3.62	$ 4.59	$ 7.48
Lower-48*	16.3	17.5	18.8	19.5
Imports				
Canadian	1.3	1.8	2.0	2.5
Mexican	—	—	—	—
LNG	**	0.5	0.8	0.8
Alaskan Gas Pipeline	—	—	1.2	1.2
Other Supplemental Sources	0.1	0.1	0.2	0.2
Totals (rounded)	17.7	19.9	23.0	24.2

* Lower-48 Production includes gas from tight formations, coal seams, and co-production.

** Less than 25 Bcf.

Note: See Table IX-3 for more detail.

Section II

Introduction

Natural gas is a premium and environmentally benign fuel. It represents "about one quarter of the country's energy use. But unlike oil, natural gas has remained for the most part a domestically-produced fuel, with only 7 percent imported. Moreover, unlike coal, natural gas burns cleanly, without soot and sulphur emissions; nor does its extraction and transportation cause the environmental damage associated with the black solid. Finally, unlike nuclear power, natural gas poses no waste disposal problem."[1]

During the early 1970s, as the United States began developing a comprehensive energy policy, the future contribution of gas energy was virtually dismissed. With years of low federally regulated gas wellhead prices resulting in declining conventional U.S. gas supplies (particularly supplies directed toward interstate markets), and the almost total absence of government or industry R&D efforts on new unconventional gas sources, the potential future contribution of gas to our nation's total energy mix was not recognized.

This attitude did not change until the 1980s when future gas supply pessimism faded in the face of new resource assessments and the successful exploration efforts of the early 1980s. It was recognized that the gas option was real and achievable on an economic basis. Domestic gas production would not have to decline if its price were allowed to rise to near competitive fuel levels in order to stimulate exploration. The possibility of increasing gas production through new technologies also was recognized. The research and development community in government and industry began to realize the additional possibilities for large supplies of gas, from improved recovery techniques, unconventional sources, and through the gasification of the nation's vast coal resource.[2]

The potential for obtaining gas energy from a wide variety of sources, most of which are domestic, combined with the environmental and economic advantages of gas, its efficient storage characteristics and the vast million-mile, existing U.S. pipeline transmission and distribution system, has resulted in a broad recognition of the potential of gas energy. The principal focus in discussions of gas energy today versus ten years ago is that price, demand and environmental issues have replaced availability as the preeminent current issues.

Purpose of Report

The A.G.A. Gas Supply Committee prepared this report to assess the U.S. gas supply outlook and the principal factors that influence future gas supplies. The report offers the consensus view that large resources of gas are available, that those resources can be developed and that the numerous sources of gas supply will respond in a somewhat complementary manner under varying technological and economic conditions.

Earlier versions of the report have been utilized by A.G.A. member company personnel, government planners and policy makers, financial industry professionals, gas marketing representatives, gas producers, and the full spectrum of energy consumers. This audience has demonstrated keen interest in the consensus gas industry perspective on future gas supply, and with this report, the Gas Supply Committee is again responding to that interest.

The Committee first decided in 1979 to undertake a comprehensive study to examine the outlook for conventional and supplemental sources of gas energy to the year 2000. That report, published in 1980, focused primarily on the potential for supplemental gas supplies. This initial study has since been updated four times—in 1982, 1983, 1985 and 1987. The recent studies have provided a more comprehensive analysis of the feasible supply options.

As the reader will discover, the A.G.A. Gas Supply Committee believes that, during the next two decades, natural gas supply availability will increase to satisfy expected demand.

Footnotes

[1] *Energy Future* edited by Daniel Yergin and Robert Stobaugh; authors are I. C. Bupp, Frank Schuller, Mel Horwitch, Sergio Koreisha, Modesto A. Maidique, A Report of the Energy Project at the Harvard Business School, 1979.

[2] *Workshop on R&D Priorities and the Gas Energy Option*, Aspen Institute for Humanistic Studies, June 1978.

Section III

Projected Energy Demand

Government agencies and industry groups periodically publish long-range projections of energy demand which can be useful in establishing a probable range of future U.S. energy requirements. Several representative forecasts of U.S. energy demand are discussed below.

The demand forecasts included in this study are intended to add a demand perspective to the supply analysis, only. The supply scenarios of the Gas Supply Committee are not demand constrained and, therefore, may not match demand forecasts for a given time period. Indeed, each demand forecast is based on a different set of assumptions and are not themselves absolutely comparable. In addition, the following demand forecasts are not intended to support or address any particular supply scenario.

The range for many energy demand forecasts has narrowed in recent years. For example, most forecasters now typically project total energy consumption in the year 2000 at 90-91 quadrillion Btus (quads). But as recently as 1979, forecasts of energy consumption of up to 125 quads were common. The lower projections now prevalent are due both to more modest projected economic growth rates that are assumed to prevail past the year 2000 and to anticipated reductions in energy use per unit of aggregate economic output resulting from the improved efficiency of energy-consuming equipment.

Gas demand forecasts examined for this report generally anticipate annual economic growth rates to 2010 to average 2.5%. In addition, by 2010, gas demand in the referenced studies is expected to increase by 12% from 1988 levels. Gas will continue to supply between 20% and 25% of total energy use for the nation through the forecast period. Also of interest, for any given year, gas demand forecasts vary only slightly among the five experts cited in this report. In fact, for any given year, the five forecasters vary no more than 10% and as little as 2% from the mean of the values forecasted for that year. On average, forecasters anticipate gas demand of 18.4 quads in 1990 increasing to 20.7 quads by 2010.

Figure III-1 shows demand projections from five sources and highlights years 1990, 1995, 2000 and 2010. The figure illustrates the considerable agreement among forecasters of gas energy demand in this nation. An additional brief description of the projections and assumptions of each demand forecast is contained in Appendix A.

TABLE III-1

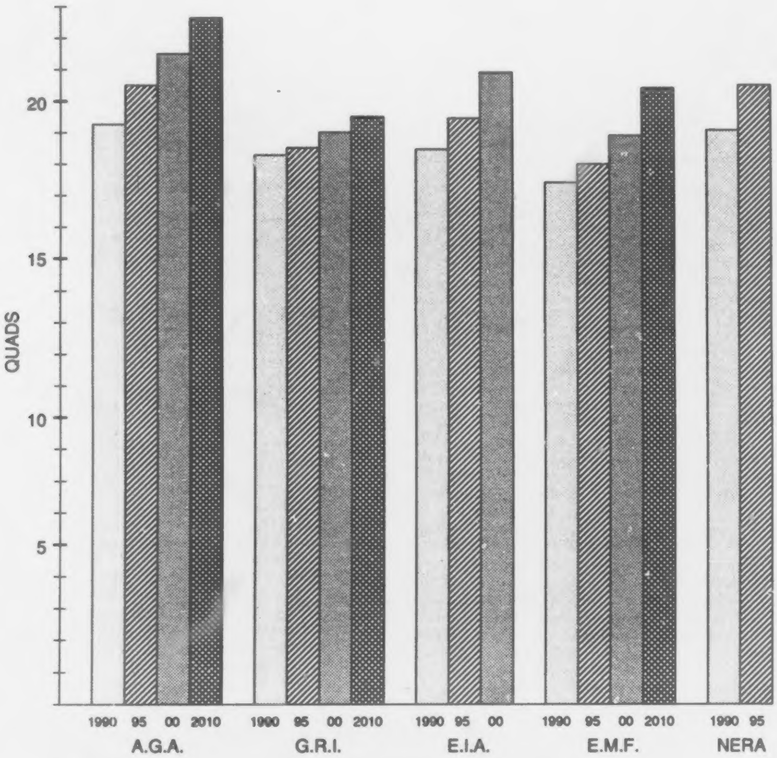
Natural Gas Demand
(Quads)

	1990	1995	2000	2010
A.G.A. TERA	19.2	20.6	21.6	22.7
GRI Baseline Projection	18.2	18.6	19.0	19.6
EIA Base Case Forecast	18.5	19.5	20.9	–
EMF (Upper Oil Price Scenario)	17.9	18.0	18.9	19.4
NERA	18.05	19.5	–	–
Mean	18.4	19.4	20.2	20.7
Largest percent variance from mean	4.3%	7.2%	6.9%	9.7%

Total Energy Demand
(Quads)

	1990	1995	2000	2010
A.G.A. TERA	81.5	86.2	90.2	97.5
GRI Baseline Projection	82.7	86.6	91.4	99.8
EIA Base Case Forecast	81.6	85.8	90.6	–
EMF (Upper Oil Price Scenario)	–	–	–	–
NERA	–	–	–	–
Mean	81.9	86.2	90.7	98.7
Largest percent variance from mean	1%	.5%	1%	1%

FIGURE III-1
Projections of Natural Gas Consumption (Demand) in the U.S.



Source: A.G.A. – American Gas Association, TERA Analysis 89–1.
G.R.I. – Gas Research Institute, Baseline Projection Data Book–1988 G.R.I.
E.I.A. – Energy Information Administration, Annual Energy Outlook, 1989-2000.
E.M.F. – Energy Modeling Forum, Stanford University, December 1988.
NERA – Marion B. Stewart, Economics Energy Consultant.

Section IV

Lower-48 Natural Gas Production

Introduction

Natural gas production in the lower-48 states is expected to account for more than 80 percent of total annual U.S. gas supply through the year 2010. In this section, gas supplies from lower-48 sources ranging from traditional sand and carbonate reservoirs to tight formations, shales and coalbeds are discussed. It should be noted that previous *Gas Energy Supply Outlook* assessments have highlighted non-traditional formation reservoirs such as tight sands, shales and coalbeds as incremental sources of gas supply. However, technological progress in the past decade has caused these resources to be reclassified and they are now properly included in the "conventional" resource base. The total physical inventory of gas supplies that may be available to the nation include proved gas reserves as estimated by the Department of Energy (DOE) and the A.G.A. Committee on Natural Gas Reserves and unproved gas resources estimated by the Potential Gas Committee (PGC) and DOE. These gas resources are producible within a narrow range of economic and technological conditions. Estimated quantities of proved reserves and potential resources are discussed and evaluated in detail in this section, along with statistical trends in drilling activity, production and reserve additions, which serve to define the health and state of the natural gas industry.

The A.G.A. Gas Supply Committee, since its first workshop in May 1979, has periodically evaluated the long-term outlook for conventional U.S. natural gas supplies. Since the inception of these studies, the objective has been to compare, understand and reconcile major disparate estimates of future U.S. conventional gas production and to develop estimates of future production capability that would represent a consensus of the gas transmission and distribution industry.

To achieve these objectives, the Committee has reviewed and discussed a series of reports prepared by individual authors or working groups in the following areas:

- comparison of major estimates of potential gas resources,
- review of trends and current statistics on drilling activity, discoveries, reserves and prices,
- evaluation of methodologies and results of available gas forecasting models, and
- study of estimates of future reserve additions and production by major gas producers, gas transmission companies, government agencies and others.

Currently, over 92% of the gas consumed in the U.S. is produced from lower-48 sources. These sources will continue to provide the largest (although diminishing) share of the total U.S. supply through the year 2010. Most gas that will be produced over the next twenty years are currently categorized as either proved reserves or potential resources. Proved reserves includes gas from geologic formations where, as a result of drilling and engineering evaluation, gas is known to be producible with the current technology and prices typical of the recent past. To a large extent, this gas has been booked by producers as a company asset. Potential resources, for the purposes of this report, include gas from those areas identified by the PGC and DOE as prospective for gas production. The potential resources include geologic basins in which drilling has occurred as well as areas which have yet to be drilled, but, as a result of geologic and engineering judgments, are believed to contain natural gas reservoirs (see discussion below).

Estimates of undiscovered resources of natural gas are, by their very nature, subject to a considerable degree of uncertainty. Nevertheless, because such estimates are essential for future planning of energy supplies, the Gas Supply Committee has supported an ongoing review of the major supply estimates. The review began by using an updated report by the PGC which analyzed the similarities and differences among the resource base estimates.[1] More recently, the PGC report for year-end 1988[2] (published in 1989) and the DOE resource assessment dated May 1988[3] were also evaluated. These reports represent the widely referenced potential gas assessments. Taken together, these reports suggest a general agreement concerning the estimates of remaining recoverable natural gas resources in the United States.

Resource Estimates

Many estimates of conventional natural gas resources include at least two separate categories:

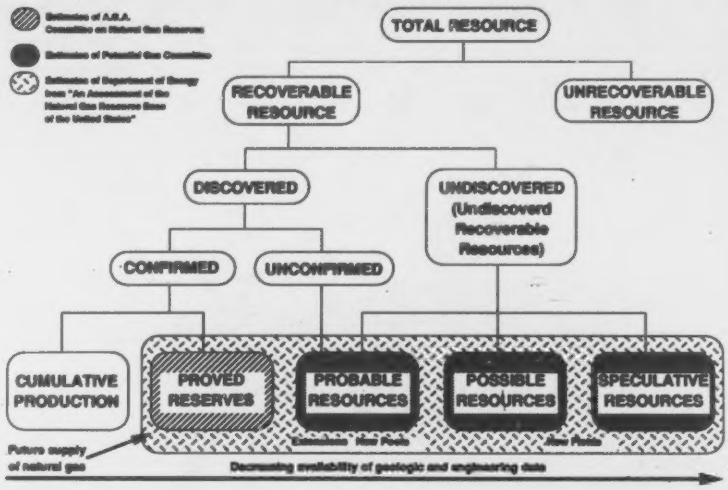
- estimates relating to known fields, i.e., resources to be recovered through extensions and new pool discoveries; and
- estimates relating to future discoveries outside of known fields.

As shown in Figure IV-1, PGC subdivides its estimates of resources which would be recoverable from future new field discoveries into possible resources (related to future new field discoveries in formations which are already productive) and speculative resources (related to future discoveries in formations and/or provinces which are not currently productive). The estimates of potential resources recoverable from known fields are reported by the PGC as probable resources.

The PGC's methodology is based on geologic analyses of potential producing areas, and is dependent upon the expertise of the members of the Committee. Members represent all segments of the gas industry and a wide variety of companies, including producers, pipeline companies and distributors. There are also representatives from academic institutions and state and federal agencies. The strengths of the PGC lie in the expertise of its members and in the periodic reevaluation, generally biennially, of estimates using consistent methodology and parameters. The estimates of the Committee have changed somewhat through the years, reflecting new information based on exploration and production history. Current PGC estimates of undiscovered gas resources in the United States are shown in Table IV-1. PGC estimates the most likely quantity of recoverable undiscovered gas in the lower-48 states to be 677 Tcf at year-end 1988.[2] This estimate includes 90.1 Tcf of coalbed methane estimated and quantified individually for the first time in the PGC report published in 1989.

In the latest PGC reports, more detailed information was considered and is reflected in the estimates than was the case

FIGURE IV-1
Reserve and Resource Classification
Committee on Natural Gas Reserves, Potential Gas Committee, Department of Energy


Estimates of A.G.A. Committee on Natural Gas Reserves
Estimates of Potential Gas Committee
Estimates of Department of Energy from "An Assessment of the Natural Gas Resource Base of the United States"
TOTAL RESOURCE
RECOVERABLE RESOURCE
UNRECOVERABLE RESOURCE
DISCOVERED
UNDISCOVERED (Undiscoverd Recoverable Resources)
CONFIRMED
UNCONFIRMED
CUMULATIVE PRODUCTION
PROVED RESERVES
PROBABLE RESOURCES
POSSIBLE RESOURCES
SPECULATIVE RESOURCES
Extensions
New Pools
New Fields
Future supply of natural gas
Decreasing availability of geologic and engineering data

in earlier reports. PGC members have reviewed geologic and exploration data and have made separate resource estimates for 89 individual geologic provinces in the lower-48 states and Alaska. Additionally, within each province, and for each of the probable, possible and speculative categories, maximum and minimum estimates have been formulated along with the most likely estimate. Presentation of this range of estimates documents the uncertainty involved in resource estimation, particularly in regions where there are little data. The maximum estimate represents the maximum quantity of natural gas which PGC members believe might be present within the province if the most favorable of conditions were to exist. These most favorable conditions are judged to be highly unlikely, and there is considered to be a probability of only 10 percent or less that this much recoverable gas would actually exist. The minimum estimate represents the minimum quantity of natural gas which has a very high probability (probably 90 percent or greater) of occurrence even if only the most marginal of conditions actually exists. The most likely estimate represents the best judgment of PGC members as to the most likely quantity of natural gas which can be expected to occur in the province. For convenience of comparison, most likely estimates are used, but it must be borne in mind that these most likely estimates represent the point judged to have the highest probability of being correct within a wide range of uncertainty.

Regional estimates of potential resources of natural gas compiled by the PGC at the end of 1988 are summarized in Table IV-1 and the PGC regions are illustrated in Figure IV-2. The estimates of potential resources indicate that the estimates for the most likely value for future gas resources (including both growth of known fields and undiscovered resources), regardless of the time necessary for development and recovery, and assuming a favorable economic climate, are generally on the order of 587 Tcf of natural gas still remaining to be discovered in the lower-48 states. When coalbed methane (90.1 Tcf) is added to the resource base, remaining sources potentially available reach 677 Tcf. If proved reserves are included, total known and potential gas resources in the lower-48 states amount to about 831 Tcf, or the equivalent of about 50 times the 1988 production level.

The DOE method of assessing the gas resource base utilized expertise from leading gas resource specialists to reach a consensus regarding the extent of the U.S. resource base and its economic recoverability. Unlike the PGC, which presented cumulative estimates on a geographic basis, DOE aggregated estimates by resource categories highlighting such resource categories as extended reserve growth in nonassociated fields and reserve growth attributed to gas associated with oil fields. Extensive study of reservoirs, fields and geologic plays were used to define or extrapolate the contributions of these categories to the potential resource base. Like PGC, DOE recognized the significant contribution of low-permeability formations, Devonian shales and coalbeds to the gas resource base.

Beyond the cooperative effort to define the technically

TABLE IV-1

Potential Gas Committee Estimates of Potential Gas Resources — 1988

(Tcf)

Area	Probable	Possible	Speculative	Total
Atlantic				
Onshore	22.0	8.2	31.0	
Offshore	**	**	15.5	
Total	22.0	8.2	46.4	76.6
North Central Total	1.8	6.9	10.3	18.9
Gulf Coast				
Onshore	22.8	35.9	16.0	
Offshore	26.5	55.2	47.2	
Total	49.3	91.1	63.2	203.6
Mid-Continent Total	45.8	61.7	31.6	139.1
Rocky Mountains Total	44.0	55.0	20.8	119.8
Pacific				
Onshore	1.6	6.2	6.5	
Offshore	0.1	9.0	5.8	
Total	1.7	15.2	12.3	29.1
Lower-48 States				
Onshore (less than 15,000′)	96.1	109.1	78.1	
Onshore (more than 15,000′)	41.8	64.8	38.0	
Offshore	26.6	64.2	68.4	
Total	164.5	238.0	184.6	587.0
Coalbed Methane				90.1[1]
Total Lower-48 States				677.1
Alaska				
Onshore (less than 15,000′)	6.4	16.4	27.7	
Onshore (more than 15,000′)	**	**	*	
Offshore	2.4	12.7	53.0	
Total	8.8	29.1	80.7	118.6
Total United States	173.2	267.1	265.3	795.6

[1] Most likely estimate of recoverable resource.

* Negligible quantity of resource estimated.

** No probable or possible resource estimated.

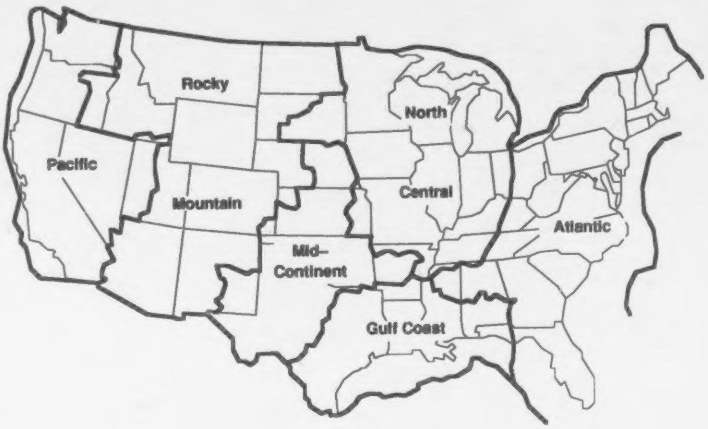
Note: Totals subject to rounding.

recoverable resource base, participants were asked to judge that part of the resource base recoverable at specific wellhead prices. Benchmark prices of $3.00/Mcf ($1987) and $5.00/Mcf ($1987) were established using resource cost estimate trends developed by the GRI Hydrocarbon Model, the Geological Associates and ICF-Lewin. Economically constrained estimates by the Geological Associates, U.S. Geological Survey (USGS), Minerals Management Service (MMS), Energy Information Administration (EIA) and others were also examined. The quantities of technically recoverable gas resources as well as the resources judged recoverable by the DOE study participants at less than $3.00/Mcf ($1987) and less than $5.00/Mcf ($1987) are listed in Table IV-2.

DOE assessments of the potential resource base are generally higher than the PGC estimates. A comparison of PGC and DOE estimates is presented in Table IV-3. However, when narrow economic criteria (such as recoverable gas at less than $3.00/Mcf) constrain the individual resource estimates of the May 1988 DOE assessment and the earlier (December 31, 1986) PGC assessment DOE and PGC estimates independently predict a recoverable resource base of almost 425 Tcf. At the very least, this reaffirms the belief that a large economically recoverable resource base exists in the lower-48 states.

The addition of coalbed methane to standard resource estimates is a function of the rapidly advancing technology and increasing production levels from key areas such as the San

FIGURE IV-2
Potential Gas Committee Regions Lower-48 States



Juan and Black Warrior basins. Coal is both a source bed and a reservoir bed for the gas; the production of this gas is subject to conditions which differ considerably from those governing production from conventional sandstone or limestone reservoirs. Considerable research, new insights into the potential of coal-rich basins throughout the United States, and the increasing production levels have enhanced perceptions of coalbed methane's contribution to the resource base.

Estimation of the recoverable quantity of undiscovered natural gas resources is a dynamic process based on evaluation of the data available concerning resource occurrence and distribution, the technology available for resource development, and the economic conditions which control exploration, development and production. There is a shifting interface between technically and economically viable resources and those which are submarginal. Changes in either technology or economics will result in changes in resource estimates. Changes in methods of exploring for gas, such as greater understanding of the conditions of formation, migration and accumulation of natural gas, also lead to new evaluations of resource potential. Additionally, new technology plays a role in exploration because, through the development of new exploration tools such as improved seismic data or better evaluation of the source rock potential of a given formation, the improved technology enables the explorationist to make a better analysis of the possibility of occurrence of recoverable resources. Improved technology may also lead to development of resources in more remote or difficult areas which might not previously have been susceptible to development.

Proved Reserves

Proved reserves of natural gas, as defined by the A.G.A. Committee on Natural Gas Reserves and the Department of Energy's Energy Information Administration (EIA), are those quantities of natural gas about which there is a "reasonable certainty" of recovery under current operating and anticipated economic conditions. In other words, proved reserves are those resources which have been discovered as a result of drilling activity and can be produced with present-day technology and currently anticipated wellhead prices. Reserves and future additions to reserves are the basis for future production and are highly dependent upon drilling and prices. As in previous reports, the Gas Supply Committee has closely reviewed the issues and trends concerning drilling and prices.

Historical statistics concerning proved reserves and the reserve life index in the lower-48 states are illustrated in Figures IV-3 and IV-4, respectively (also see Appendix C). Twenty years of steady growth in proved reserves occurred up to 1967, at which time the reserves were 289.3 Tcf. After that peak year and prior to 1981, annual production was larger than annual reserve additions. As a consequence, reserves decreased steadily. Figure IV-5 illustrates the lower-48 production and reserve additions since 1947. In the time period from 1960 through 1970, federally-established wellhead prices (below the cost of alternate fuels) caused consumers to increase demand for natural gas, but also caused producers to reduce exploration for new reserves. The consequences of this became apparent after 1968 when lower-48 annual reserve additions dropped below 12 Tcf.

TABLE IV-2

DOE Assessment of the Natural Gas Resource Base—May 1988

(Tcf)

	Technically Recoverable Gas	Recoverable Gas	
		<$3.00/Mcf	<$5/Mcf
Lower-48			
Inferred Reserves/Probable Resources	85	85	85
Inferred Reserves, Offshore	23	23	23
Extended Reserve Growth in Nonassociated Fields, Onshore	119	56	74
Gas Resources Associated with Oil Reserve Growth	61	30	41
Undiscovered Onshore Resources	219	88	147
Undiscovered Offshore Resources	134	54	82
Gas in Low-Permeability Reservoirs	180	70	119
Shale Gas	31	10	15
Total	852	416	586
Coalbed Methane	48	8	12
Total Lower-48 States	900	424	598
Alaska			
Inferred Reserves (Cook Inlet Area)	3	3	3
Alaska Undiscovered, Onshore and Offshore	93	2	4
Total	96	5	7
Total United States	996	429	605

By 1973, after 6 years in which reserve additions were less than half of annual production, the level of annual production began to decrease. Production declined significantly between 1973 and 1979. Since 1980, gas production has followed an erratic track, rising in 1981, 1984, 1987 and 1988 and falling in 1982, 1983, 1985 and 1986. By 1979, the gas supply situation began to improve due in large part to the passage of the Natural Gas Policy Act of 1978 (NGPA) which was designed to increase the incentives to find new gas and thereby increase gas supplies. This legislation permitted higher prices for recently-discovered gas and deregulated the price of most of this gas by January 1, 1985. In addition, a single market was created whereby intrastate and interstate sales of gas would be governed by a uniform set of price ceilings.

The results of the NGPA from a proved reserves viewpoint were impressive. In 1981, reserve additions for the total U.S. were 114 percent of production. Lower-48 states reserve additions in that year were reported by EIA to be 21.56 Tcf—the highest level of reserve additions since 1959. Relatively strong reserve additions continued to be reported from 1980 to 1987 as the ratio of reserves added to production for the lower-48 states averaged 89 percent. This ratio for 1987 dropped to 69 percent due to the greatly-reduced level of drilling activity since 1986. However, 1988 replacement levels likely surpassed the recent average of 89 percent. This is supported by the fact that among the thirty top U.S. gas reserve holders, 103 percent of production was replaced in 1988. The record since passage of the NGPA is in contrast to the 45 percent replacement ratio during the decade preceding passage of the NGPA. The Gas Supply Committee believes that the ability to increase reserve additions has been demonstrated given adequate market prices and gas demand and that many of the earlier long-term forecasts of rapidly declining production have been proven wrong.

TABLE IV-3

Comparison of PGC/DOE Resource Estimates

(Tcf)

	PGC	DOE
Lower-48 States Total	587.0	852.0
Coalbed Methane	90.1	48.0
Total Lower-48 States	677.1	900.0
Alaska Total	118.6	96.0
Total United States	795.6	996.0

NOTE: The DOE estimate, as published in "An Assessment of the Natural Gas Resource Base of the United States," May 1988. For the purpose of comparing DOE and PGC totals, the proved reserves are not included in the volumes tabulated in this table.

FIGURE IV-3
Proved Natural Gas Reserves Lower-48 States

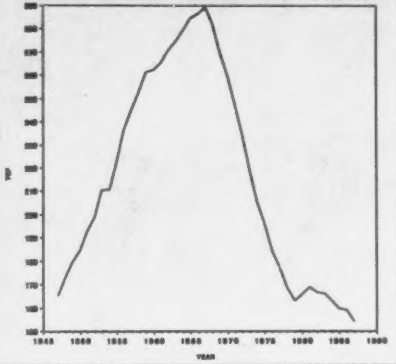


FIGURE IV-4
Reserve Life Index Lower-48 States

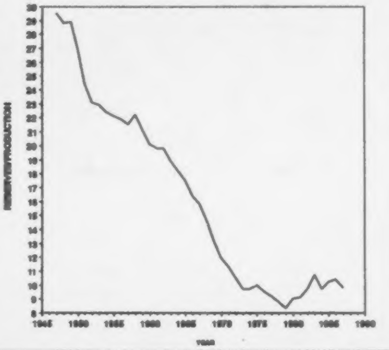
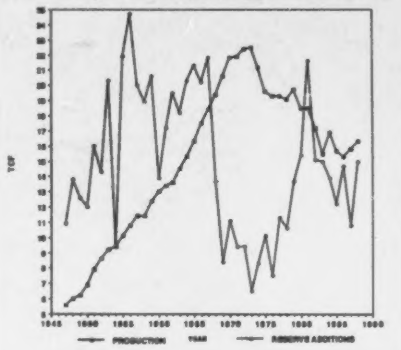


FIGURE IV-5
Production vs. Reserve Additions Lower-48 States



NOTE: 1988 Reserve additions estimated

Figure IV-6 illustrates the potential gas (based on PGC estimates), proved reserves and cumulative production for the lower-48 states from 1966-1987. The consistency of the PGC estimates of ultimately recoverable gas is apparent. Also noteworthy is the steady reduction of proved reserves over this 21 year period—a reflection of the rising costs of maintaining a large reserves inventory. Despite the steady increase of cumulative production, less than half of the lower-48 ultimately recoverable resource had been produced by year-end 1988.

Drilling Activity

Increasing demand for natural gas contributed to increased gas directed drilling through much of the 1970s. With passage of the NGPA in 1978, this activity received a significant boost (see Figures IV-7, IV-8, and IV-9). Rig counts, seismic crew counts and gas well completions reached all time highs in 1981 (19,910 gas wells were completed).

While this drilling activity strengthened production capability, reduced demand led to the so-called "natural gas bubble"—production capability and deliverability exceeded the demand for gas. The lower production levels after 1979 were the result of reduced demand for gas and not a limitation in production capability. In fact, production capability remained well above actual demand through the 1980s. Estimates placed the excess deliverability, or bubble, in 1983 as high as 4.6 Tcf. The bubble began to shrink after 1983 and production capability and demand are expected to be in balance during 1990. As a result of the bubble, many producers experienced difficulty in selling gas at high delivery rates or at maximum permissible NGPA prices. These marketing problems caused significant reductions in drilling, beginning in 1983. This reduction in drilling activity accelerated between 1983 and 1988 as continued producer reaction to the disincentive for drilling created by the gas bubble and generally declining wellhead prices manifested itself.

Although current levels of gas well completions are depressed from recent years, they are not exceptionally low from a historical perspective. Figure IV-7 shows the growth in gas well completions since 1968. It is seen that, with the exception of the peak drilling period 1979-1985, the number of gas well completions in 1988 was higher than any other year in history prior to 1975-1985.

Undoubtedly, gas well completions will need to be increased above the 1988 level before additions to proved reserves can again achieve the 1980-1983 levels. Nevertheless, there are several positive effects which arise from the current retrenchment in drilling. For instance, although the number of rigs operating, as shown in Figure IV-8, has been reduced from the peak levels of over 4,000 to less than 1,000 for the past two years, there has been increased efficiency as marginal equipment and inexperienced drilling crews have been removed from the system. These efficiency increases are on the order of 60% to 80% on a national basis. Due to this increased efficiency, as well as to increased competition and general energy pricing declines, the cost of drilling has declined significantly from peak levels of the early 1980s. A conclusion from these observations

FIGURE IV-6
Estimates of Ultimately Recoverable Natural Gas Resources, 1966-88
Lower-48 States

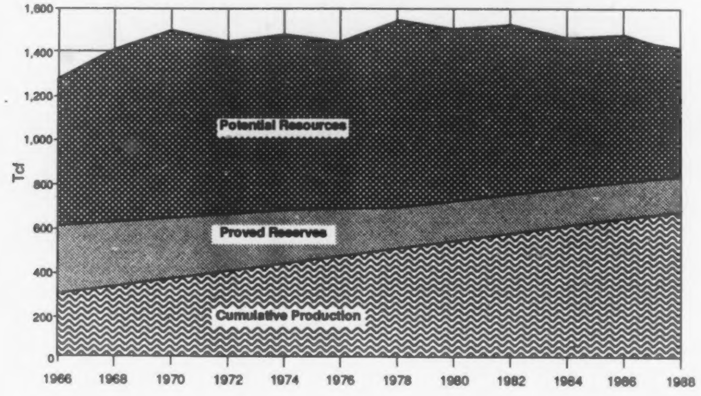


FIGURE IV-7
Gas Well Completions Lower-48 States

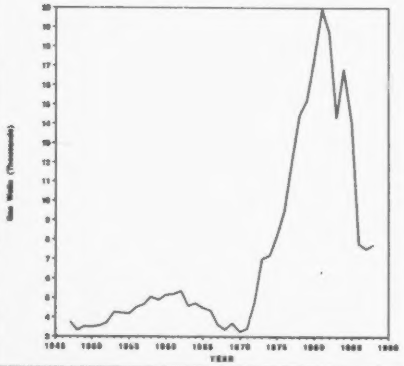
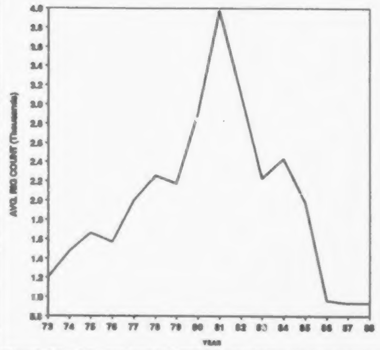


FIGURE IV-8
Average Weekly Rotary Rig Count



is that in spite of lower rig counts future reserve additions could occur at lower drilling costs than those which characterized traditional areas during the early 1980s. However, efficiency gains alone can not offset rig count levels of less than 1,000 in the long-term. Investment and hardware must return to the field in the form of seismic crew activity and rig counts in order to improve reserve replacement and to insure long-term domestic supplies of natural gas.

FIGURE IV-9
Average Monthly Seismic Crew Count

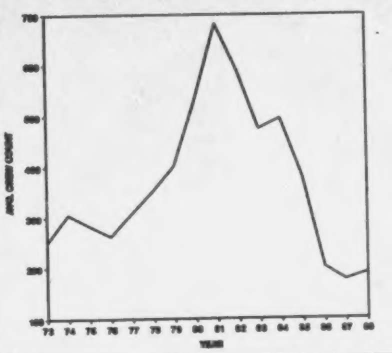
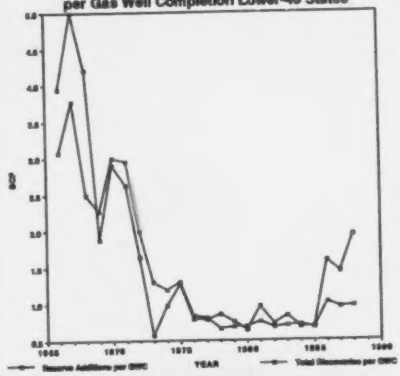
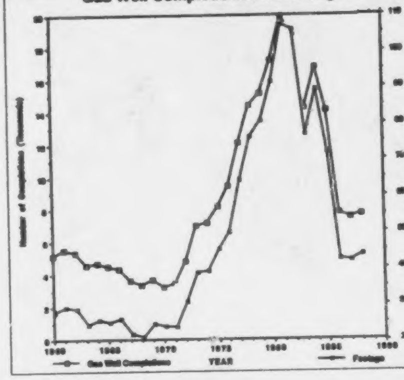


FIGURE IV-10
Reserve Additions versus Total Discoveries
per Gas Well Completion Lower-48 States



NOTE: 1988 estimated

FIGURE IV-11
Gas Well Completions and Footage

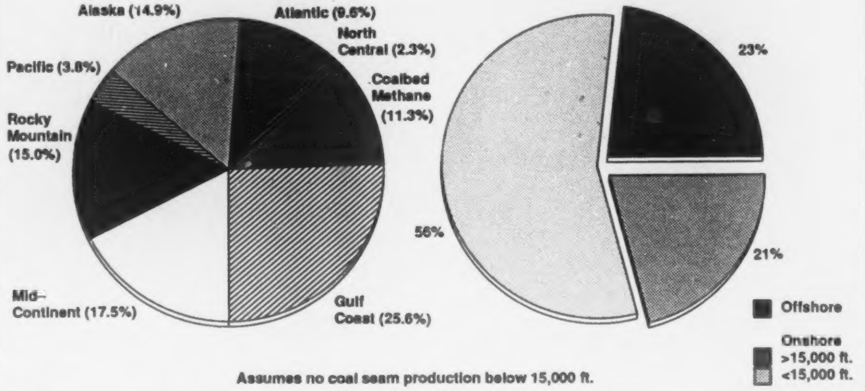


The data plotted in Figure IV-11 are critical to an analysis of future gas supplies. This figure illustrates gas well footage drilled as well as gas well completions. Annual gas well completions is a comprehensive statistic which includes some exploratory and deep gas wells which may be dominant in finding new reserves. But also, it includes relatively shallow wells in heavily-explored regions—some with only modest expectations of adding large new gas reserves. For example, the total gas well completions statistics do not adequately reflect the exploratory drilling activity in the Gulf of Mexico which is the most important gas prone producing area in the U.S. today. Similarly, the reserve additions statistics are aggregated to include not only the discoveries of a given year but the economic, technical and geologic reassessments (revisions) of earlier discoveries. Because of these factors, various groups have traditionally interpreted these statistics differently. Despite these differing opinions, the Gas Supply Committee believes that the deregulation of new exploration and production activity has clearly demonstrated that, with vigorous drilling activity, the capability exists to add reserves at rates close to replacing production.

The volume levels of PGC gas resource estimates support this thesis. However, current drilling has not matched the potential. Most drilling now occurring has been directed at already extensively exploited resources which, consequently, hold little promise for very large new discoveries. Even after a decade of the NGPA drilling incentives, Figures IV-12 (Resources) and IV-13 (Gas Well Completions) show that the 1983-1988 distribution of drilling activity was very different from the estimated distribution of the resources. The drilling activity occurred in areas more in accordance with the likelihood of maximizing near-term return on investment. This is especially true when demand for gas is limited and economic targets for both exploratory and development drilling are likely to be selected in areas of relatively high chance for success, but rather low yield per well. These areas tend to be regions of past and continuing gas production in which producers are familiar with geologic conditions and where supporting services, such as pipelines and drilling services, are in place. From this standpoint, the shallow, conventional natural gas resources of the lower-48 states remain an attractive drilling target; consequently, over 90% of the gas wells completed in 1983-1988 were drilled to develop these known resources. In contrast, strong markets for natural gas would encourage exploration in regions where the percentage of successful wells is lower, but the potential return on investment from a successful well is many times that of a low-risk, low-yield well. In these cases, with greater certainty of a market for yet-undiscovered gas, producers should be willing to incur the exploration and development costs in support of major discoveries. Thus, apparently significant but underdeveloped resources in deeper parts of sedimentary basins and in offshore regions could support a vigorous and growing natural gas market.

FIGURE IV-12

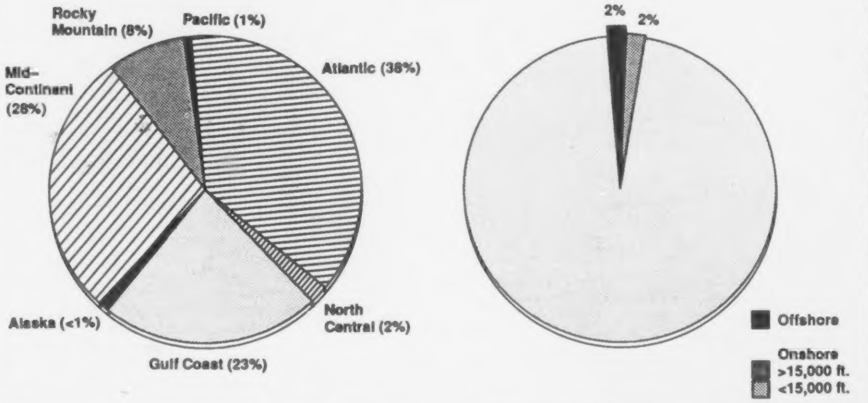
Distribution of Estimated Natural Gas Resources (PGC-1988)



Assumes no coal seam production below 15,000 ft.

FIGURE IV-13

Geographic Distribution of Total U.S. Gas Well Completions (1983-1988)



- As shown in Figure IV-12 approximately 15 percent of the potential is in Alaska and 85 percent is in the lower-48. Of the lower-48 total (including coalbed methane), 56 percent is in shallow lower-48 onshore regions, 21 percent at depths of more than 15,000 feet, and nearly 23 percent in the offshore areas. Simply stated, nearly half of our gas potential is in "hard to develop" areas.
- As shown in Figure IV-13 drilling activity is dominated

TABLE IV-4

Lower-48 Production Estimates

(Tcf)

	Low Price Scenario	Middle Price Scenario	High Price Scenario
1995-2000-2010			
Oil Price ($1988/bbl)	18-22-33	20-27-40	30-38-62
Gas Price ($1988/MMBtu)	2.33-3.03-4.84	2.59-3.63-5.52	3.62-4.59-7.48
1995	15	16.9	17.5
2000	15	18.0	18.8
2010	15	18.5	19.5
Cumulative Production (1989-2010)	334	387	402
Remaining Lower-48 Resources (2010)	494	441	426

Note: See Figures IV-5 and IV-6 for the historical perspective from 1966-1988.

by lower-48 onshore shallow well completions that accounted for 96 percent of all gas well completions. The offshore and deep well completions, only four percent, are not nearly matched to their supply potential.

Production Estimates

The Gas Supply Committee has developed the lower-48 conventional supply estimates which are presented in Table IV-4. The estimates for available gas supplies in 1995, 2000 and 2010 from lower-48 states resources are a result of considerations of current gas industry and government analyses, including detailed modeling using the A.G.A. TERA Model and the GRI Hydrocarbon Model as well the most recent government supply studies published by the DOE. Estimates have been developed under the three supply scenarios previously described to indicate the variability of the lower-48 supply as a function of different economic conditions. The High Price Scenario contains an estimate consistent with strong, real price increases in energy prices starting in 1990. The Middle Price Scenario is typical of what would be produced with modest real energy price increases through 1995 and then prices increasing at a rate of 4.7 percent each year. The volumes in the Low Price Scenario characterize the production consistent with stable prices through 1995 and then a growth rate of about 4 percent per year. The specific scenarios which elaborate on these assumptions are described in the Executive Summary.

Implicit in the production levels presented in Table IV-4 are certain levels of activity in gas well completions, certain levels of future reserve additions and a rate of depletion of proved reserves and potential resources. Historically, many forecasts of natural gas supply have been excessively influenced by an extrapolation of short-term trends. For example, in the early 1960s, when production generally increased each year, most forecasts assumed that these increases would continue indefinitely. As a result, extraordinarily high lower-48 production forecasts were commonplace in this period. As natural gas shortages became a reality in the 1970s, however, forecasts reversed and began to be very pessimistic.

Table IV-5 presents a comparison of the demonstrated historical levels of several variables related to lower-48 conventional production and typical values of these variables for the volumes in the production profiles presented in the Committee forecast. The all-time peak year for gas well completions was 1981 when 19,910 gas wells were completed. The forecasts for future conventional lower-48 production presented by the Committee are believed to be achievable with lower levels of gas well completions—about 16,000 wells per year or less but even in the high price scenario never exceeding 20,000 gas well completions per year. Likewise, additions to proved reserves remain well below historical demonstrated highs. Reserves to production ratios decline slightly in the Committee forecasts for each price scenario. This trend is primarily indicative of structural changes in the natural gas industry as opposed to a declining resource. Thus, the reserves to production ratio is expected to decline to about 8.5 to 1 by 2000, even in the most demanding scenarios. The level of natural gas reserves added per gas well drilled is assumed to be nearly constant at about one Bcf per well. Although major technological innovation (unforeseen) could improve this level, the production estimates described do not depend on such assumptions.

Survey of Forecasts of Conventional Gas Production Capability

A review and analysis of lower-48 U.S. natural gas production capability estimates prepared by major oil and gas production companies, consultants, government agencies and the A.G.A. was undertaken by the Gas Supply Committee in 1988. Data in Table IV-6 are the result of that review process. To the extent that information on assumptions or methodology has been provided by the estimators, it was used to group similar estimates in Table IV-6. These forecasts were not made with the same assumptions as those for the scenarios presented by the Gas Supply Committee. Therefore, the categorizations into the low, medium and high price groupings of these non-Committee estimates are only for general comparative purposes.

TABLE IV-5

Typical Parameters Implicit in Lower-48 Production Estimates

Parameter	Actual Range 1975-1987	Estimated Range for Scenarios from 1995-2010 Low Price	Middle Price	High Price
Production (in Tcf)	16.1-19.3	15.0	16.9-18.5	17.5-19.5
Gas Well Completions	9,440-19,910	10K-12K	15K-16K	15K-18.5K
Reserve Additions (in Tcf)	7.5-21.6	13-15	18-19	18-21.5
Reserves to Production Ratio	8.3-10.7	8.7-9.0	8.6-8.8	9.2-9.6
Reserves Added Per Gas Well (in MMcf per Well)	640-1,220	1,000	1,000	1,000

Low Price Scenario: Production levels forecast for 1995-2010 is lower than production levels since 1963. As a result, levels of gas well completions and reserve additions are typical of the lower range of these parameters in earlier years. The reserves to production ratios and the reserves added per gas well are expected to be in the ranges observed from 1975-1987.

Middle Price Scenario: Production levels forecast for 1995-2010 are lower or in the lower portion of the range experienced earlier. Gas well completions and reserves added per gas well are typical of or more conservative than earlier data. Reserve additions in this scenario tend toward the higher levels which were recorded in the early 1980s. Reserves to production ratios are expected to be lower because of the producers' desires to lower the inventory costs associated with high reserve to production ratios.

High Price Scenario: Production levels in this scenario are typical of the higher levels achieved in the 1975-1985 period. Not surprisingly, the gas well completions and reserve additions are also similar to the higher historical levels of those parameters. The reserves to production ratios are expected to be in the same range from 1995-2010 as they were in the 1975-1985 period. Reserves added per gas well are conservatively estimated to be in the historical range.

Note: The parameter ranges shown in this table are indicative of the exploration and production requirements necessary to achieve the production levels tabulated for each scenario. Trade-offs exist between the parameters listed—a lower level of reserves could be compatible with lower numbers of gas well completions. The intent of the table is to indicate to the reader the general level that these parameters would reach under a particular scenario.

Resource Base Refinements

In past years, lower-48 production estimates have been separated into "conventional" and incremental "unconventional" components. This report no longer uses that distinction. Instead, gas reservoirs such as tight sands, coal seams and Devonian shales are incorporated into the "conventional" gas supply mix, if the resource is judged to be recoverable under the same criteria as was used for the "conventional" resource. The year-end 1988 report from the Potential Gas Committee recognizes that technology and developing production histories have altered not only tight sand and Devonian shale gas, but also the coalbed methane and co-production from "incremental" gas supply resources to the supply mainstream. Indeed, the PGC specifically estimates coalbed methane's contribution to the lower-48 resource base at 90.1 Tcf.

Estimating the separate contributions made by each type of resource to the resource base is difficult. The following discussion briefly highlights several reservoir types and provides a general understanding of the contribution made by each to the total resource base.

Tight Formation

As part of the incentive wellhead pricing formula offered by the Natural Gas Policy Act (NGPA) of 1978, productive tight formations were defined by FERC to be certain reservoirs with permeabilities of less than 0.1 millidarcy (md). Permeability is the measure of a rock's ability to transmit fluids. In general, low permeability rocks transmit the gas slowly to the wellbore. Methods of enhancing the flow of gas from low permeability reservoirs have resulted in the development of sophisticated fracture treatments applied to key formations after a well is drilled. Incentive pricing was (in the late 1970s) judged necessary to offset the cost of such completion techniques and to encourage exploration for these "slow-yield" reservoirs.

Subsequent to initial passage of the NGPA, fracture treatments have become increasingly commonplace in the completion of wells for many reservoir types. In fact, as the lower-48 natural gas resource base is more extensively developed, production and exploration activities have moved increasingly into areas characterized by low permeabilities. In many of these areas, the resource costs for low permeability production are quite modest. With more advanced technologies, resource costs could be further reduced. This would be particularly important for areas where low permeability resources currently have high production costs under current technology.

Western tight gas sands are a prime example of this phenomenon. The emerging potential of the Rocky Mountain states to be a significant center for gas production has been, in part, a result of growing technology in the areas of geologic assessment and well completion techniques. Exploration and production activity is so commonplace among tight sand reservoirs that separating these resources from the traditional resource base has become difficult. Therefore, the PGC now includes in the undifferentiated resource base (see Table IV-1) those tight sand reservoirs deemed able to meet the criteria of producibility at accepted levels of technology and economics.

Devonian shales of the Appalachian basin also qualify as

TABLE IV-6

Aggregated Lower-48 Production Estimates

(Tcf)

Source	Low Price 1995	Low Price 2000	Low Price 2010	Middle Price 1995	Middle Price 2000	Middle Price 2010	High Price 1995	High Price 2000	High Price 2010	Comments
Amoco	15	13	–	17	16	—	—	—	—	from "Lower-48 Production Outlook," November 1988.
Chevron	13.5	13.5	14.9	—	—	—	—	—	—	informal correspondence from C.A. Jordan, General Manager, Natural Gas Supply and Marketing, Chevron, U.S.A., January 17, 1989.
Martin/Campbell	15.8	15.1	15.5	16.7	17.7	18.1	—	—	—	from "Natural Gas: A Strategic Resource for the Future," Washington Policy and Analysis, 1988. Gas supply estimates referenced as Baseline Case (Low Price) and New Gas Environment Case (Middle Price).
Gas Research Institute (GRI)	16.0	16.0	13.8	16.5	16.7	15.3	16.5	18.3	17.7	GRI production estimates include Alaska gas production used in Alaska or exported as LNG to Japan.
Energy Modeling Forum	14.45	14.92	14.79	16.69	17.25	17.11	17.31	18.12	18.7	from Energy Modeling Forum, Stanford University, December 1988. Lower Oil Price (Low Price), Upper Oil Price (Middle Price), High U.S. Demand (High Price) Scenarios utilized. Low Resource case omitted.
EIA	17.7	18.8	—	18.1	19.0	—	17.2	18.4	—	from Energy Information Administration, "Annual Energy Outlook 1989".
TERA	—	—	—	17.6	18.2	16.2	—	—	—	from A.G.A. model, TERA Base Case 1989-1.

tight formations capable of gas production. These shales are a series of gas-productive or potentially gas-productive siltstones and shales of middle-Devonian age lying in a thick wedge of marine and terrestrial rocks that make up the large Catskill Delta complex. Many of the shale and siltstone reservoirs of Pennsylvania, New York, Ohio, Kentucky, West Virginia and southwestern Virginia qualify as tight formations. However, many of these reservoirs have been extensively drilled for many years in Appalachia. Resource estimates for tight gas in the Appalachian basin have ranged from 225 Tcf to 1,861 Tcf, depending on the type of analysis and the volume of black and/or gray shales used in the analysis.[4] Such resource estimates have generally been replaced with estimates of those resources recoverable by available technology and economics. Therefore, such resources are now included in the mainstream of PGC resource estimates.

While it is generally thought that Devonian shale is a high cost resource, detailed resource estimates indicate that, even with current technologies, a substantial share of Devonian shale gas resource is recoverable at modest costs. Institutional considerations, however, such as low takes and producer financial risk, lead to higher cost expectations by many producers. Takes should improve as the "gas bubble" ends. New technologies can reduce the risks in areas of current activity as well as reduce the basic resource costs for high cost Devonian shale areas.

Certainly, future advances in technology may influence the estimates of recoverable resources from both tight sands and Devonian shales. Almost without doubt, growth in technology will help the economics of producing some low permeability reservoirs. The DOE resource assessment of 1988 placed the technically recoverable low permeability and shale gas resource at 211 Tcf. Time and technology may even prove this estimate to be conservative.

Coalbed Methane

In 1988, the Potential Gas Committee estimated 90.1 Tcf of coalbed methane is likely to be recoverable from key sedimentary basins in the lower-48 states. This resource estimate is additive to other PGC most likely estimates and represents 13.3 percent of the total lower-48 resource base. Without question, coalbed methane has penetrated the resource mainstream and can no longer be considered only an incremental source of natural gas for the United States. The penetration of coalbed methane into the resource activity has relied heavily on the basin assessments and reservoir simulation models developed by the Gas Research Institute. Table IV-7 lists by basin the contribution of individual areas to the coalbed methane resource as estimated by the PGC. To date, the San Juan basin of northwestern New Mexico and the Black Warrior basin of northwestern Alabama have dominated the coalbed methane drilling activity in the United States.

In 1988, nearly 1.0 Tcf of reserve additions were added to proved natural gas reserves in the U.S. from coalbed methane drilling activities. Companies such as Amoco and Burlington Resources (through its Meridian subsidiary) plan significant investments in drilling programs in 1989 and 1990 to develop this gas resource.

TABLE IV-7

Potential Gas Committee Estimates
Coalbed Methane Resource
(Tcf)

Basin	Most Likely Recoverable Resource
Appalachian	25.0
Warrior (Black Warrior)	8.0
Illinois	0.4
Piceance	29.7
San Juan	27.0
Total	90.1

Note: Arkoma, Powder River, Wind River, Greater Green River, Uinta, Raton Mesa and western Washington basins, though containing coal deposits, were not estimated.

Coalbeds act as both source and reservoir rock. Evaluations of the coal seam gas resource indicate that large amounts of methane exist in the nation's coal deposits. These estimates are frequently based on an estimate of the coal resource in tons multiplied by an estimate of the gas content of the coal. The methane content of coals varies widely—both between different coals and within the same coal seam in different locations. Establishing an average or even a range of methane per ton of coal is difficult. The DOE and others have evaluated the coal seam methane potential of 16 major geologic basins. Although the estimates of the in-place resource vary widely, the volumes generally range upwards to 800 Tcf. Of that total, PGC estimates that 90.1 Tcf are recoverable.

To produce methane adsorbed in coal seams, two things must occur: a natural or artificial pathway from the coal face to the wellbore must be found or created, and the hydrostatic pressure must be lowered to the point where gas will desorb. Conventional drilling techniques and technologies must be adapted to perform these two tasks.

Well stimulation and slant drilling can create pathways. Horizontal boreholes in coal mines can also create effective pathways. Fortunately, many gaseous coal seams are relatively shallow. However, care must be taken when drilling, fracturing and completing, since, to differing degrees, fracturing proppants, drilling mud and the cement used to set casing may plug the natural fractures in the coal bed.

Since many coal seams contain significant amounts of water, hydrologic characteristics must be considered. Often, dense well spacing is necessary to produce enough water to sufficiently lower hydrostatic pressure and thereby allow the methane to desorb. In some cases, special measures are necessary to properly dispose of the water produced. Abrasive coal fines increase wear on pumps and thus can increase operating and maintenance costs. Improper fracturing operations may increase formation pressure and prevent desorption.

Coal mining plays an important role in the development of the coal seam methane resource. Projects undertaken in advance of mining attempt to both produce commercial amounts of methane and reduce the risk in mining operations. Coordination with mining operations is necessary to avoid mining through the wells before terminating production from the wells. Questions over legal ownership of the methane and possible damage to the seam roof have impeded production in advance of mining.

Wells can also be drilled into mined-through ("gob") areas. Gob wells exploit the fractures in the remaining coal rubble as well as mine dewatering to produce volumes far in excess of wells into unmined seams (a good gob well can peak at 1500 Mcf/d of mixed gases). However, the typical gob well produces about half its total production in the first six months and plays out in about three years. In 1987, the Warrior basin in Alabama produced an estimated 16 Bcf of gas. Much of that total was from gob wells. It has been estimated that if all of Alabama's recoverable coal seam methane is recovered in conjunction with mining operations, the pace of mining will stretch gas production over almost a millennium.

By June 1988, 449 wells were producing coalbed methane in the Black Warrior basin. Cumulatively, 60 Bcf of pipeline quality gas has been produced since serious exploration and development began early in the 1980s. The pace of new well permitting and quarterly production growth has increased dramatically in recent years.[5]

The thinner, deeper coal seams in the western United States will probably not be mined. An estimated 3 Bcf of gas was taken from coal seam wells in the San Juan basin in 1986. In addition, the San Juan coal seams are interspersed with sandstone, and it is impossible to say how much more coal seam gas is being produced from conventional gas wells.

The dense spacing, high operating costs and low production rates typical of coal seam wells (other than gob wells) demand high take levels for projects to be economically viable. Also, coal seam gas is produced at very low pressures and requires a significant amount of fuel gas for compression to pipeline specifications.

Prices have been sheltered to some degree from the fall in gas prices by existing Section 107 contracts and the Internal Revenue Code Section 29 tax credit. The credit is currently over $.70/MMBtu. However, the credit is available only for the gas produced before January 1, 2001 from wells drilled or a facility placed in service before January 1, 1991.

In spite of the difficulties, methane from coal seams has been demonstrated to be a viable source of gas. Experience in producing coal seam methane and efforts by private companies, the DOE and GRI to develop the required technology have led to growth in coal seam methane production.

Methane from Co-production

Co-production is a secondary gas recovery technique which involves the production of large volumes of brine to make possible the production of gas. The co-production target reservoirs vary from the widespread, diffuse resource base of gas in solution in brine to the high concentrations of gas trapped in specific known locations after primary production.

The Texas-Louisiana Gulf Coast area has been the primary area for evaluation of co-production potential. This is because the extensive prior exploration and production in this area provide an exceptionally strong base of geological and engineering data. These data clearly indicate a co-production resource large enough to be of substantial significance to the nation.

The resource amenable to gas recovery by co-production of gas and brine consists of both an enormous low grade, high cost base and smaller resource amounts in higher quality deposits that are producible at lower costs.

The low grade, high cost portion of the resource includes an enormous quantity of gas in solution in brine in sandstones and shales. The USGS and the DOE geopressured/geothermal programs have provided estimates of up to 100,000 Tcf for the solution gas-in-place in the Texas-Louisiana Gulf Coast area. At the same time, it is recognized that much of the solution gas resource is not recoverable due to prohibitive economics. Extensive drilling of wells specifically for production of this solution gas (which includes gas from geopressured-geothermal reservoirs) is not expected prior to 2010 under any of the Committee's price scenarios.

At the other end of the spectrum, the highest quality portion of the resource base is in known locations where gas cap production was terminated due to high pressure brine invasion.

Co-Production is accomplished by completing and producing wells as brine wells. High brine production rate reduces fluid pressure in the pores to below "trapping pressure." The gas is then "mobilized" and is produced with the brine. Recovery of "attic gas" is another important aspect of co-production. Attic gas is free gas that was abandoned above water when upward "coning" into perforations caused production of brine with the gas.

The amount of gas producible by co-production from the highest quality portion of the resource base can be estimated only roughly. This is because of the limited data available concerning the remaining gas-in-place in abandoned wells. Additional nonrecoverable resources have long been acknowledged to exist. But, the amount of gas that remains in reservoirs when continuing production is no longer economically viable for the operator is seldom determined and historical data has not been compiled. The Institute of Gas Technology (IGT) estimates that co-production potential is on the order of 60 Tcf.

Production estimates for methane from co-production are based on encouraging results from work in progress. Certainly, current technology and economics have shifted methane co-production from that of incremental to mainstream supply source. For example, co-production wells in the N.E. Hitchcock Field (Texas) which were co-funded by Gas Research Institute and the producer, have produced more than 1.5 Bcf of natural gas. The project has proved economic at prices less than $2.00 per MMBtu. Effective control of calcium carbonate scale has been demonstrated in the field as has disposal of more than 20 million bbl of brine into a single injection well with only a few hundred psi of pressure at an injection rate of 25,000 bbl/day. Small producers are now using co-production technologies in six fields in southeast Texas and more fields are scheduled to go on-line in 1989.

Footnotes

[1] *Potential Gas Committee, A Comparison of Estimates of Ultimately Recoverable Quantities of Natural Gas in the United States*. Gas Resources Studies, No. 1, Potential Gas Agency, Golden, Colorado, 1977.

[2] *Potential Gas Committee, Potential Supply of Natural Gas in the U.S., as of December 31, 1988*, May 1989.

[3] U.S. Department of Energy, *An Assessment of the Natural Gas Resource Base of the United States*, May 1988.

[4] National Petroleum Council, *Unconventional Gas Sources, Devonian Shale*, Volume III, June 1980.

[5] Gas Research Institute, *Quarterly Review of Methane from Coal Seams Technology*, Volume 6, Number 2, November 1988.

Section V

Gas Imports

Canadian Gas

Natural gas imports from Canada have been the most important supplementary source of gas supply to U.S. markets. During the 1970s and 1980s, imports from Canada ranged from 740 to 1,268 Bcf per year. In 1988, the peak level of 1.3 Tcf of gas, or just over 7 percent of U.S. gas consumption, was imported from Canada. Between 1990 and 2010 this level could grow to around 10 percent of U.S. consumption, or, as much as 2.5 Tcf/year. The passage of the U.S.-Canadian Free Trade Agreement (FTA) will serve to provide more secure gas supplies to the U.S. and more stable access to markets for Canadian producers. Within this context, the amount of gas imported from Canada will depend on a number of factors, including Canadian producer pricing policies, concerns over the rate of resource development, the rate of growth of gas demand in Canada, export pipeline capacity and the impact of changing markets on U.S. gas resource development. Between 1990 and 2010, development of the Canadian and Alaskan frontier areas and the construction of transportation systems for this gas will significantly impact the level of exports. However, the size of the Canadian gas resource is not viewed as a factor which would significantly limit the amount of gas available for export in the time horizon of this report.

Canadian Resource

Canadian natural gas resources are as varied as those in the United States. They include both conventionally producible non-associated and associated-dissolved gas and unconventional resources, such as low permeability formations. Canadian drilling activity, as in the United States, continues to emphasize less expensive, more traditionally-produced resources. However, there is a growing interest in the more costly frontier areas of the Atlantic offshore, Mackenzie Delta, Beaufort Sea and the Arctic Islands (see Figure V-1). Gas resources in these regions have higher development and transportation costs because of the extremely hostile conditions imposed by nature and the long distances between the production sites and the markets. In the near term, the production emphasis will be on the conventionally produced gas resources. In the longer term, the frontier areas will provide an important supplement to the traditional production areas.

Established reserves of marketable natural gas, as estimated by the Canadian Petroleum Association (CPA), were 94.3 Tcf at year-end 1988 (see Table V-1).[1] Of this, 82.4 Tcf are non-associated and 24.6 are located in so-called "frontier areas." Not included in the CPA estimates are the vast undiscovered gas resources of Ganada. In a separate evaluation, the Geological Survey of Canada in 1984 estimated Canada's total recoverable gas resource (including reserves) to be approximately 426 Tcf.[2] This estimate will be updated soon and the total undiscovered resource could be substantially increased if the "Deep Basin" area of Alberta and British Columbia, or the Eastern offshore discoveries in the Sable Island and Hibernia areas, are judged to be as important as some industry experts estimate.

TABLE V-1

Marketable Natural Gas Remaining Established Reserves in Canada[1]

(Bcf)

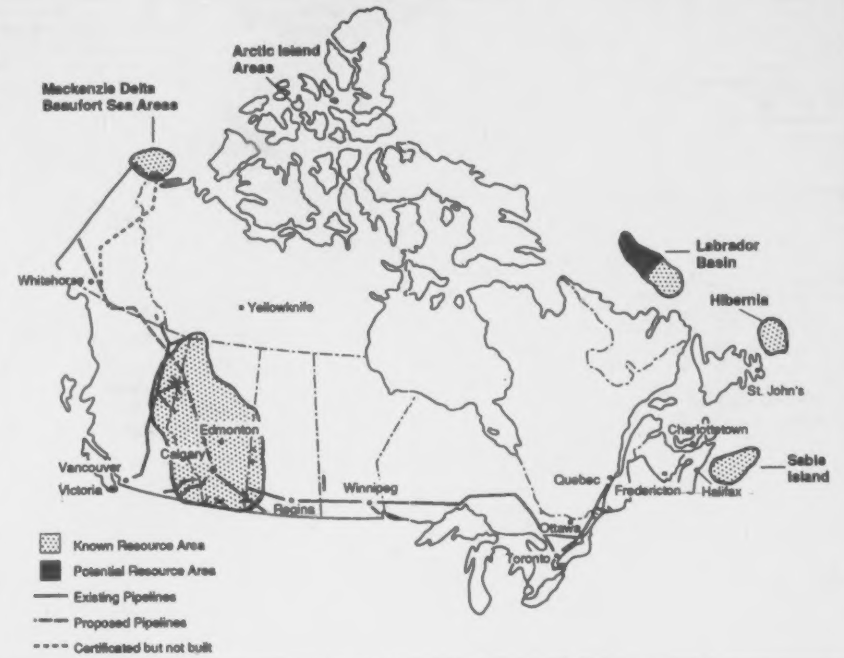
Area/Province	1988 Net Production[2]	Remaining Reserves[2]
Alberta	3,123	59,590
British Columbia	292	7,417
Saskatchewan	141	1,987
Ontario	8	646
Other Eastern Canada	0.5	3
Frontier		
Mainland Territories	4	396
Mackenzie Delta-Beaufort Sea	–	9,889
Arctic Islands	–	14,345
Total[3]	3,569	94,273

[1] *Natural Gas Reserves of Selected Fields in the United States and of Canada – Prepared by the American Gas Association and the Canadian Petroleum Association as of December 31, 1988*, published June 1989.

[2] All volumes at 14.73 psia, 60°F.

[3] Totals subject to rounding.

FIGURE V-1
Natural Gas in Canada


Arctic Island Areas
Mackenzie Delta Beaufort Sea Areas
Labrador Basin
Hibernia
Whitehorse
Yellowknife
St. John's
Edmonton
Charlottetown
Calgary
Sable Island
Vancouver
Victoria
Winnipeg
Quebec
Fredericton
Halifax
Regina
Ottawa
Toronto
▨ Known Resource Area
■ Potential Resource Area
Existing Pipelines
Proposed Pipelines
Certificated but not built

Production of gas in Canada was 2.8 Tcf in 1987; thus the reserves to production ratio (R/P) based on CPA estimates is over 30.[3] By contrast, the U.S., with proved reserves in 1987 of 187.2 Tcf and production of 16.1 Tcf, has an R/P of about 12.[4]

In whatever way the Canadian resource potential is viewed, the above estimates indicate that Canada has adequate resources to meet its own domestic needs and to maintain or increase gas exports to the United States.

Canadian Production

Production in Canada grew significantly in the period 1960-1988, increasing from just under .5 Tcf per year to approximately 2.8 Tcf per year.[1,5] Since the late 1970s, annual production has fluctuated between 2.2 and 2.9 Tcf per year.[5] However, information from Canada's National Energy Board (NEB), indicates that the existing production capability was significantly higher than actual production during the last several years.

Developing a substantial future production capability in Canada through the development of new resources will involve problems similar to those in the United States in that much of the potential resource lies in remote areas and offshore. In addition, development in the arctic regions will require the construction of technically advanced and costly gas transportation systems to meet the harsh conditions of the arctic environment. At present, established supplies in more accessible areas are sufficient to meet demand; and current economics do not justify the higher costs of development of these more challenging resources. However, in the late 1990s, gas prices may increase to levels at which development of these resources becomes economically attractive.

Exploration activity in Canada is largely concentrated in the western provinces, including some activity in the Elmworth Deep Basin. Similar to drilling activity in the U.S., Canadian exploration has slowed somewhat recently; and, as already mentioned, there are a number of areas where production is below maximum capability. Thus, there is less incentive to drill additional wells because of the difficulty in selling the gas, not unlike the situation which has prevailed in the U.S.

As mentioned, Canada has some 24 Tcf of reserves located in frontier areas. The Mackenzie Delta/Beaufort Sea area with over 10 Tcf of proven reserves and some 66 Tcf potential has already been the subject of hearings and filings with the Canadian National Energy Board regarding export authorizations and pipeline projects.

Also of significance to future U.S. imports, especially to the New England area, is development in the Sable Island and Hibernia areas off the east coast. The Sable Island area, located on the Scotian Shelf off of the coast of Nova Scotia, covers approximately 60,000 square miles and more than 75 wells have been drilled. Discoveries have been made at depths between 11,000 and 17,000 feet. Higher than normal porosities, high recovery factors and high flow rates all have contributed to estimates of potential gas reserves ranging up to 12 Tcf. Agreements to market gas in the northeast U.S. from the Venture field near Sable Island have been secured by producers in Canada and several U.S. gas companies. In summary, the development of other Canadian gas resources can be expected to proceed as adequate markets for the gas emerge.

U.S. Imports from Canada

Although Canada's resources are adequate to continue or expand exports to the United States, the actual volumes exported will depend both on the new policies under the FTA which are adopted by Canadian and U.S. regulatory agencies and the impact of U.S. market conditions on U.S. gas resource development. Canadian policy may reflect concerns based on the expansion of the Canadian domestic market, the rate of Canadian gas resource development, the cost of gas developed in the frontier areas, and the price of alternate energy supplies. In particular, the expectations of significant long-term growth in domestic Canadian gas demand and the need to maintain adequate reserves to meet that demand must be integrated with the current utilization of production capacity to generate additional revenues for Canada and enhance Canadian resource development. In this context, the U.S. market is extremely important from the Canadian perspective.

The actual level of gas exported by Canada could be influenced by future Canadian regulatory decisions regarding expansion of pipeline facilities. Nevertheless, current Canadian policy favors increasing exports and the Canadian government has demonstrated a willingness to let the competitive market work.

During the 1980s, the Canadian government has moved away from setting prices to a practice of monitoring prices of natural gas exports. In November 1985, *The Agreement on Natural Gas Markets and Prices* became effective. This agreement between the federal and provincial governments called for deregulation of the domestic Canadian gas market by November 1986. This agreement reestablished the principle of a negotiated market oriented pricing system for gas exports rather than a continuation of controlled prices. However, exporters were required to demonstrate that the negotiated contractual agreements met certain criteria. This resulted in significant declines in price and generally increased the market sensitivity of prices at the border. As a result, Canadian export prices averaged slightly less than $2.00/MMBtu in 1988 compared with $4.01/MMBtu as recently as 1984.

With deregulation and the increased flexibility surrounding import/export transactions, the number of short-term sales (agreements with a term of two years or less) increased dramatically. In 1985 those sales accounted for a very small percentage of the total (less than 2%). However, by 1986 over 20%, and by 1988 over 30% of all gas imported flowed under short-term agreements.

Historically, during the years when Canadian exports were 1.0 Tcf or less, imports during the peak load months of December and January were about twice those of the slack summer months. In contrast, the high level of imports in 1988 improved the load factor of the importing pipelines so that, in aggregate, the summer loads were about 80 percent of the maximum winter month deliveries. The overall strength of the export market for Canada has led to proposals for a number of projects to transport gas under long-term agreements. Many of these proposals involve significant construction and/or expansion of existing facilities which would increase the capacity for transporting Canadian gas.

Import Estimates

Table V-2 presents a range for possible U.S. imports of Canadian gas in 1995, 2000 and 2010 under the Committee's three price scenarios. As indicated in each scenario, the level of imports could potentially grow to 1.7 to 1.8 Tcf per year by the year 1995, and with proper pricing, could even increase to a level of 2.5 Tcf per year by the year 2010.

TABLE V-2

U.S. Natural Gas Imports from Canada
(Tcf)

Year	Low Price Scenario	Middle Price Scenario	High Price Scenario
Oil Price ($1988/bbl) (1995-2000-2010)	18-22-33	20-27-40	30-38-62
1995	1.7	1.8	1.8
2000	1.8	2.0	2.0
2010	1.8	2.5	2.5

The Low Price Scenario estimates little additional growth beyond 1995 because Canadian resource development is limited by low prices. Acting as a stimulus for exports are the Canadian revenue objectives which impact upon the rate of resource development for domestic Canadian gas supply. Thus, development of frontier area resources begins near the end of the report period. In this scenario, Canadian gas demand actively competes with U.S. demand for Canadian supplies thereby further discouraging increased export levels. For this reason, exports achieve a level of 1.7 Tcf by 1995 and increase to 1.8 Tcf by 2000 and remain at that level through the year 2010.

In the Middle Price and High Price Scenarios, anticipated growth beyond 1995 is predicated on:

- a Canadian policy which emphasizes the need for maintaining and/or increasing revenues from gas exports and therefore, is responsive to U.S. market changes.
- Canadian gas resource development in frontier areas such that future production capability can adequately serve Canadian domestic demand and a growing export market.
- the expansion of transportation facilities for gas exports.

The development of projects in the frontier areas results in additional volumes being available to Canadian and U.S. markets such that 2.0 Tcf could be imported by the year 2000, and, by 2010, 2.5 Tcf could be imported.

Mexican Gas

Imports from Mexico to U.S. markets were suspended in November 1984 and had not resumed by year-end 1988. Between 1980 and 1984 however, the U.S. imported between 50 and 105 Bcf of gas per year from Mexico. The large Mexican resource base and its high production capability make Mexico's gas exports an important potential gas supply for U.S. markets. Whether or not imports are resumed and the degree to which supplies of Mexican gas are made available to the U.S. will depend on Mexico's energy requirements, political factors between and within Mexico and the U.S., and gas pricing policies. Changing economic factors related to world oil prices and the financing of Mexican foreign debt will also play a significant role. It is possible that gas imports from Mexico could resume in the time horizon of this study.

Mexican Resource

Natural gas in Mexico exists as a conventionally producible resource both associated with oil and in non-associated deposits. Gas and oil fields have been discovered along much of the Gulf of Mexico coastal plain with current production coming from both onshore and offshore fields. A significant non-associated gas province, the Sabinas basin, is located in northern Mexico. In recent years, there has also been an increased interest in gas and oil resources in western areas of the country such as those near the Gulf of California.

As of January 1, 1989, proved reserves were 74.8 Tcf with a reserves to production ratio of 60.[7] New estimates of the size of the undiscovered gas resource are not available from PEMEX, but were previously estimated to be over 289 Tcf.[8] Mexico's total gas resource base has been questioned by the U.S. Department of Energy, Rand and others.[9] However, all estimates confirm the existence of a potentially large gas resource base of approximately 200 Tcf or greater. For comparison purposes, U.S. proved reserves including Alaska total 187 Tcf as of year-end 1987.[3]

Mexican Gas Production and Drilling Activity

During 1987, gas production in Mexico totaled 1.27 Tcf.[10] This was slightly less than the 1.28 Tcf produced in 1986. Overall, gas production has declined an average of 3.0% per year since 1983. About 84 percent of the gas produced in Mexico has been associated with oil, with the other 16% non-associated.

Along with the decline in gas production, exploration and development drilling has also slowed. The number of exploration wells completed dropped dramatically in 1987 to 27 wells from 68 wells in 1986. Development well completions fell even more dramatically to 76 wells in 1987 from 178 wells in 1986.[11] Overall, a total of 103 wells was completed in 1987, compared to 246 wells in 1986 and 287 wells in 1984.

The January 1989 rig count as reported by Hughes Tool was 111 land rigs and 35 offshore rigs for a total of 146 rigs—a slight decrease from the 1988 average of 155 rigs. Seismic activity has shown a similar decline falling from an average of 30 crews at work during the early 1980s to 20 crews at work during the first half of 1988.

The decline in drilling activity is due in part to a lack of funds since the federal government cut PEMEX's 1988 budget by 20% early in 1988. In addition, low world oil prices have done little to offset the risks associated with drilling activity.

U.S. Imports from Mexico

Between 1980 and 1984, U.S. imports were made under the October 19, 1979 gas-purchase-and-sale agreement between PEMEX, the national oil and gas company of Mexico, and Border Gas, a consortium of six U.S. gas transmission companies. The original contract allowed for up to 300 MMcf per day to be delivered from PEMEX at an interconnection near Hidalgo, Texas. Declining domestic demand reduced Border Gas purchases to 180 MMcf per day, or 60 percent of contract levels, effective April 1, 1983.

On November 1, 1984, deliveries of gas from Mexico were suspended under the terms of the contract for an unspecified period—a decision reached mutually by both parties to the contract.

For the foreseeable future, most of the gas produced in Mexico will come from that associated with oil production. Given Mexico's aggressive oil export policy, this implies significant gas production. Thus, the ultimate market for gas which could be produced for export will be governed in part by four significant factors:

- The results of Mexico's programs to encourage domestic natural gas consumption.
- The desirability of optimizing oil production.
- Policy considerations relating to Mexico's international trade balance, debt service considerations, and related domestic economic factors, and,
- Mexican and U.S. agreements governing the allowable price and volume of U.S. imports compatible with U.S. market conditions.

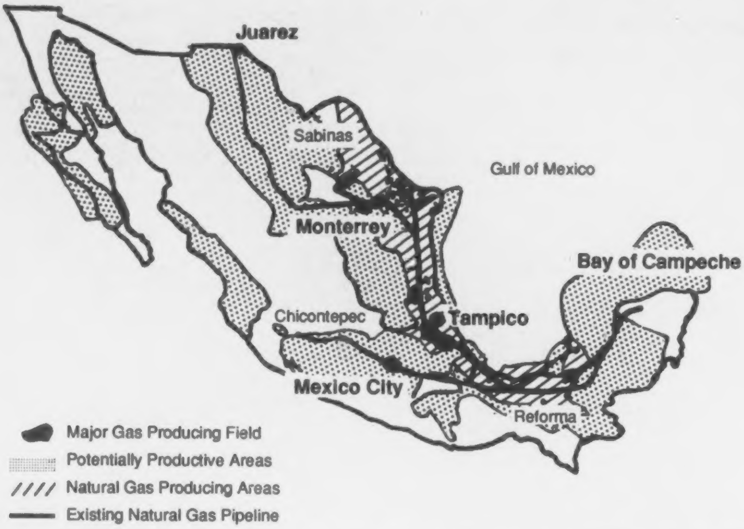
The Gas Supply Committee considered the following factors in estimating a range of volume levels available for export as shown in Table V-3: 1) falling Mexican crude production capacity, 2) increasing domestic crude demand, 3) the economic benefits of exporting gas to the United States, and 4) the gas production capability of Mexico.

TABLE V-3

U.S. Imports from Mexico
(Tcf)

Year	Low Price Scenario	Middle Price Scenario	High Price Scenario
Oil Price ($1988/bbl) (1995-2000-2010)	18-22-33	20-27-40	30-38-62
1995	—	—	—
2000	0.1	—	—
2010	0.1	—	—

FIGURE V-2
Natural Gas in Mexico


Juarez
Sabinas
Gulf of Mexico
Monterrey
Bay of Campeche
Chicontepec
Tampico
Mexico City
Reforma
Major Gas Producing Field
Potentially Productive Areas
//// Natural Gas Producing Areas
Existing Natural Gas Pipeline

U.S. imports from Mexico under the three price scenarios reflect the following:

Low Price

Gas imports will resume after 1995 at a rate equal to the original Border gas contract of 300 MMcf/d.

Middle Price and High Price Cases

All Mexican gas will be consumed internally in order to maximize exports of oil for which Mexico receives greater income.

LNG Imports

Liquefied natural gas (LNG) is conventional natural gas which is liquefied by reducing its temperature to minus 260°F at atmospheric pressure. The volume of the LNG is 1/600 that of the gas in its vapor state. This technique permits the transportation of large volumes of natural gas over great distances and geographic surfaces not otherwise suitable for pipelines.

The potential natural gas resource base for LNG includes any overseas gas reserves or production not currently committed for commercial purposes, as well as future additions to reserves beyond those required for local consumption. The potential resource base includes:

- gas produced in association with oil production which, due to lack of local commercial markets, must be flared or reinjected. Such an example would be the North Sea production of gas and oil.
- non-associated gas for which local markets or transportation do not exist. The potential Nigerian gas production is an example of large quantities of gas which do not currently have a suitable market.
- gas produced in nations for which the foreign exchange value is more significant than local consumption purposes. Indonesian gas production would be such a case.

The four U.S. LNG import terminals are located at Cove Point, Maryland; Elba Island, Georgia; Lake Charles, Louisiana; and Everett, Massachusetts. Each of these terminals was operational for some time in the 1978-1983 period. Although each terminal has been deactivated since that time, all, but the Elba Island facility, are expected to be operational again in the near future. The Everett facility resumed operation in late 1987 as a result of an agreement between Distrigas and Sonatrach, the Algerian national energy concern, which provides for market based pricing of the LNG. Shipments are expected to double during the winter of 1989-90. In the case of the Lake Charles facility, ERA approval for LNG shipments and an agreement between Panhandle Eastern Corporation and Sonatrach have made LNG shipments possible as early as the winter of 1989-1990. Columbia LNG Corporation has announced a joint venture with Shell Oil in regard to the future ownership and operation of the Cove Point facility.

In the past there was a tendency by some gas producing nations to seek wellhead price parity with oil (on a thermal basis). This, when coupled with LNG liquefaction, shipping and regasification costs caused imported LNG to be more expensive than domestic natural gas supplies. For this reason, prices sought by exporters were judged unacceptable by U.S. regulatory agencies, and widespread LNG trade to the U.S. was suspended. Today, these producing nations do not expect crude oil parity pricing or even premium LNG prices. Net-back based formulas for the sale of the regasified LNG are now more common. Not only is the traditional Algerian supplier, Sonatrach, agreeing to net-back formulas but new potential suppliers such as Nigeria, Norway and others appear eager to enter the U.S. market on similar bases. This renewed interest stems from several factors. First, most analysts believe that higher U.S. gas prices will support the investment in liquifaction plants and tankers. Second, the potential exporting countries have vast gas reserves that they are anxious to utilize. In addition, these Atlantic Basin suppliers are turning away from the European market that is somewhat stagnant and amply supplied from present sources.

At the same time as east coast terminals prepare to renew LNG imports, the U.S. exports from Alaska to Japan which began in 1969 continue. The Alaskan gas is produced near Cook Inlet and exported by Marathon Oil Company and Phillips Petroleum.

In addition to U.S. gas imports, Japan, the world's largest importer, accounts for over 70 percent of the world total LNG of 1.9 Tcf transported, with most of the remainder going to Europe. The largest exporter is Indonesia, followed by Algeria, Malaysia, Brunei, Abu Dhabi, the U.S. (from Alaska) and Libya in that order.[13]

Although LNG imports into the U.S. were essentially discontinued in the mid-1980s because of domestic oversupply and historical pricing problems, the import trade, such as the planned operation of Lake Charles and Cove Point facilities, could provide significant gas supplies as early as the 1989-1990 winter. The four existing terminals have a total annual capacity of 842 Bcf that could be returned to service in a reasonably short period of time—anywhere from 6 to 12 months depending on the facility. (See Table V-4).

All parties in a re-established trade—exporter, ship owner and terminal operator—are expected to share in the risks of current market-based pricing. Even if the price for gas drops to an extremely low point, the parties to the trade will attempt to demonstrate reliability of service which is essential for a long-term LNG import business in the U.S.

TABLE V-4

U.S. LNG Import Terminal Capacity
(Annual volumes in Bcf)

Terminals	Actual Imports 1988	Annual Capacity 1990-2000
Everett, MA	8	104
Cove Point, MD	—	365
Elba Island, GA	—	118
Lake Charles, LA	—	255
Total	8	842

When large volumes of LNG are again imported into the U.S., pricing of the gas will not be greatly different from a domestic producer selling deregulated gas at market-sensitive prices. The regulatory authorities will probably allow pipelines, LDCs and end users to contract for revaporized LNG in the same manner that other gas supplies are purchased. Such dealings require the participants in a LNG trade—exporters, ship owners, terminal operators, buyers and most importantly, regulators—to modify their earlier views of LNG.

In brief, prospects for LNG importation appear bright in that there are four under-utilized or idled LNG terminals that could be returned to service in a very short time. Both the general perception of a closer balance between U.S. gas demand and supply and a realization by LNG suppliers of the need for market-based pricing make such increased trade appear very likely by the mid-1990s.

With these key issues in mind, the estimated import levels in 1995, 2000, and 2010 for three different pricing scenarios are tabulated in Table V-5. The derivation of the volumes for 1995 assumed that all four receiving terminals would be in operation and that all imports would originate from Algeria, Nigeria and Norway. More importantly, the estimate recognizes the potential limitations that tanker availability may have on near-term import levels.

TABLE V-5

LNG Import Potential
(Tcf)

Year	Low Price Scenario	Middle Price Scenario	High Price Scenario
Oil Price ($1988/bbl) (1995-2000-2010)	18-22-33	20-27-40	30-38-62
1995	0.20	0.35	0.50
2000	0.35	0.60	0.80
2010	0.60	0.80	0.80

In the later years, it is expected that the tanker situation will be resolved, thus permitting higher volumes to be transported. The terminal utilization, and possibly liquefaction plant capacity, are likely to be the primary physical constraints in the post 2000 time period. As an example, the 800 Bcf level that could be reached as early as 2000 will require the four existing terminals to operate at 95% of their present capacity. In recognition of the potential environmental constraints, this estimate is not dependent on any new terminals being built in the foreseeable future. Nevertheless, it should be recognized that the existing four facilities can be expanded (perhaps by as much as 50 percent), which should allow additional imports if needed in the future. By the year 2000, more Atlantic rim countries could be added to the list of potential exporters and liquefaction facilities in the three nations discussed above could be expanded.

Footnotes

[1] *Natural Gas Reserves of Selected Fields in the United States and of Canada—Prepared by the American Gas Association and the Canadian Petroleum Association as of December 31, 1987*, June 1988.

[2] Procter, R. M.; Taylor, J. C.; Wade, J. A.; *Oil and Natural Gas Resources of Canada—1983*, Geological Survey of Canada, Paper 83-31; Department of Energy, Mines, and Resources, 1984.

[3] National Energy Board, *Canadian Energy, Supply and Demand 1987-2005*, Ottawa, Canada, September 1988.

[4] *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves, 1987 Annual Report*, U.S. Department of Energy, Energy Information Administration, September 1988.

[5] *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada—1979*, American Gas Association, Arlington, VA, 1980.

[6] *1976-1986 Historical Statistics of the Gas Utility Industry*, American Gas Association, 1987, Table 1-10.

[7] *Oil and Gas Journal*, Vol. 86, No.52, December 26, 1988, p.49.

[8] *The Gas Supply Energy Outlook Through 2010*, October 1987, p.32.

[9] "Constraints to U.S. Reliance on Mexican Oil and Gas Imports", H.F. Keplinger, p.10.

[10] *Petroleum Intelligence Weekly*, Vol.27, No.21, May 23, 1988, p.5.

[11] *Petroleum Economist*, Vol.55, No.10, October 1988, p.326.

[12] *BP Review of World Gas*, July 1988, page 16.

Section VI

Alaskan Gas

A major supply of U.S. natural gas is located in the state of Alaska. However, only a small part of this Alaskan gas is currently being produced due to a lack of facilities to transport the gas to markets in the contiguous lower-48 states. A proposal to transport gas by pipeline from the North Slope of Alaska, through Canada and into the lower-48 states, has already received much of the required regulatory approval. In fact, major portions of the system in the lower-48 states and Canada have been constructed and are currently used to transport Canadian gas bound for U.S. markets. Future transportation of Alaskan gas by LNG will depend on changes in U.S. markets relative to the economic feasibility of such a project.

Alaskan Resource

From a resource perspective, natural gas in Alaska, with potential recoverable resources estimated at over 150 Tcf (including proved reserves of 33 Tcf), is one of the largest natural gas supply sources in the United States. The Prudhoe Bay field on the Alaskan North Slope was discovered in 1968 and is one of the largest gas fields in the U.S., containing an estimated 26 Tcf of associated-dissolved gas reserves. Most of the remaining Alaskan proved reserves, much of which is non-associated, were discovered in southern Alaska near Cook Inlet and in other North Slope fields such as the Naval Petroleum Reserve near Point Barrow. The Cook Inlet area has been producing gas since 1959 for in state Alaskan consumption and, beginning in 1969, for export to Japan as LNG. In 1987, 349 Bcf of gas were produced in Alaska. Alaskan gas utility sales in 1987 totalled 39.7 Bcf, and 48.6 Bcf of Alaskan gas were exported to Japan as LNG. The remaining gas produced in Alaska was consumed in oil production operations or was sold directly to end-users by producers.

In addition to the current proved reserves of 33 Tcf in Alaska, the PGC estimates the potential natural gas resource in Alaska to be 119 Tcf, as presented in Table VI-1. In 1987, the DOE estimated the Alaskan potential recoverable resource to be 129 Tcf. Fifteen percent of the U.S. potential natural gas resources are expected to be found in Alaska.

Exploration activity is continuing in Alaska, although in recent years there has been little gas-oriented drilling. Following the limited success of Canadian drilling operations in the Beaufort Sea and Arctic Islands, American companies began to explore the Beaufort Sea/Mackenzie Delta area. Current market conditions and the lack of a pipeline outlet have discouraged extensive drilling for gas in Alaska; however, Alaska is still viewed as a primary source of future oil and gas supplies.

Production

Despite the fact that Alaska has such a large resource potential, there are major problems in developing this resource. First, there are difficulties with oil and gas exploration in Alaska. These difficulties include:

- *Leasing*—Alaskan offshore and onshore lease offerings have often been delayed, rescheduled, and in some instances, withdrawn by state or federal authorities. Concerns over environmental issues and the rate of resource development have, at times, restricted exploration activity by limiting access to federal lands.
- *Arctic Environment—The* Alaskan environment is one of harsh Arctic conditions. The weather and terrain often inhibit exploration activity and drilling and result in high cost operations. New drilling technology is often necessary for Arctic production.

The other major obstacle in utilizing the Alaskan gas resource is the lack of a gas transportation system to the lower-48 states.

The Alaska Natural Gas Transportation System (ANGTS) was granted approval by Congress in 1977 under the provisions of the Alaska Natural Gas Transportation Act. This project consists of a 4,800 mile pipeline from the North Slope of Alaska which parallels the TAPS oil line right-of-way south to Fairbanks, and then roughly follows the Alaska Highway into Alberta. In Alberta, the system divides into two legs which extend into the midwestern and western regions of the U.S. Construction of the pipeline is a cooperative venture of several companies sponsoring separate segments in Alaska, Canada and the lower-48 states. When complete, the ANGTS will be capable of delivering initially 2.1 Bcf per day of gas to the lower-48 states from Prudhoe Bay. With expansion, the system could deliver over 3 Bcf per day. Approximately 70% of this gas will be delivered to the midwestern and eastern U.S. via the Eastern Leg, while the remaining 30% is destined for the western states.

Currently one-third of the pipeline, known as Phase I or the Prebuild, is operational. Pacific Interstate Transmission Company began receiving gas from Pan-Alberta Gas, Ltd. imported through the Western Leg in October 1981. The Eastern Leg, extending to Ventura, Iowa, was completed in September 1982 and began flowing gas to four downstream buyers. In 1988, 412 Bcf of Canadian gas was transported through both Phase I legs of the pipeline project.

In 1988, the ANGTS partners (Northwest Alaskan and Foothills Pipe Lines) reviewed and updated the capital cost

TABLE VI-1

Alaskan Gas Recoverable Resources
(Tcf)

	Onshore[1]	Offshore[2]	Total
Potential			
Probable	6	3	9
Possible	16	13	29
Speculative	28	53	81
Proved Reserves	—	—	33
Total Resource Potential	—	—	152

[1] Onshore drilling depth to 30,000 feet.

[2] Offshore water depth to 1,000 meters.

Sources: Potential Gas Committee, Potential Gas Agency, *Potential Supply of Natural Gas in the United States (as of December 31, 1988)* (Golden, CO: Colorado School of Mines, 1989) and U.S. Department of Energy, Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1987 Annual Report* (Washington, DC: Government Printing Office, 1988).

TABLE VI-2

Alaskan Gas Supplies
(Tcf)

Year	Low Price Scenario	Middle Price Scenario	High Price Scenario
Oil Price ($1988/bbl) (1995-2000-2010)	18-22-33	20-27-40	30-38-62
1995	–	–	–
2000	–	0.8	1.2
2010	0.8	1.2	1.2

estimate for completion of the pipeline, resulting in a cost reduction of 45%, from $26.1 billion to $14.6 billion in 1988 dollars. The main reasons for the lower cost are lower inflation and interest costs, advancements in pipeline design and technology, incorporation of project test site results, reduced contingency requirements and a construction schedule shortened from 4½ to 3 years.

Given the new capital cost estimate, the levelized cost of service from Prudhoe Bay to the Midwest and California city gates is now estimated to be $3.05 U.S./MMBtu in 1988 dollars. Consequently, Alaskan gas could be competitive with lower-48 production about 1998 in the Middle Price Scenario and 2002 in the Low Price Scenario. North Slope production would be viable as soon as the project could be completed—in the mid-1990s in the High Price Scenario.

Expansion of the system to deliver total volumes in excess of 3 Bcfd could be undertaken once the system is in place. This is predicted to occur before 2010 in the Middle Price Scenario and by 2000 if prices follow the higher trajectory.

Section VII

Synthetic Gas

Coal Gasification

Resources and Technology

The United States has extensive coal reserves which are recoverable by mining. In harnessing this potential energy, a single commercial-scale coal gasification facility (250 MMcf per day of high-Btu gas production) is estimated to consume about 200 million tons of coal during its first 20 years of operating life.

Although not all coals are suitable for any given coal gasification technology, alternative conversion technologies can utilize different types of coal. Research and development efforts will expand the breadth of coal feedstock that specific conversion methods can accept. In light of continuing advances in the gasifier technologies, which will make the utilization of virtually all types of coal reserves possible, vast coal reserves exist in the United States for the production of synthetic gas.

Coal to gas conversion requires both chemical and physical transformation. The high-Btu coal gasification processes that already exist, or that are under development, share five major steps; coal preparation and pretreatment, gasification,[1] shift conversion,[2] gas purification and methanation.[3] For medium-Btu gas production, shift and methanation are omitted.

Synthetic gas can be produced from coal either by mining and processing through surface gasification plants or by using *in situ,* (i.e., underground gasification) techniques (see Section VIII). Depending upon the mode of conversion and the degree of processing, the resulting Btu content of gas produced through coal conversion ranges between 100 and 1,000 Btu per cubic foot of gas. In comparison, pipeline gas from conventional naturally occurring sources typically has a Btu content of approximately 1,000 Btu per cubic foot.

Consequently, synthetic gas production with a Btu content of about 1,000 Btu per cubic foot (SNG) is considered to be of pipeline quality and a supplement for conventional gas in present pipeline systems. In contrast, because of economic considerations, medium-Btu gas (generally less than 500 Btu per cubic foot) is only suitable for combustion applications on-site or at relatively short distances away from the production facility.

Despite this incompatibility with natural gas, medium-Btu gas could become an important part of gas utility operations in the future. Medium-Btu gas offers utilities the opportunity to provide gas to industrial customers through existing delivery systems where the use of conventional natural gas or direct use of coal may be prohibited by regulatory constraints.

Comparative Costs and Advantages

Based on coal's expected cost and its national security advantages over imported oil, development of the nation's coal resource as part of a long-term energy strategy is particularly desirable. The direct use of coal in homes and most commercial and small industrial applications is, however, prohibitively expensive. Consequently, conversion of coal to a more usable and broadly acceptable form is necessary before coal can be widely used. There are three main forms of conversion: electricity, gas (methane), or liquids (petroleum substitutes). A large number of studies comparing coal gas to other coal conversion products have been conducted in recent years. While each of these products has its unique advantages and place in the national energy picture, coal gasification is particularly advantageous:

- The production of coal gas will enable the continued use of the in-place million-mile gas transmission and distribution network which represents a near $90 billion investment. Moreover, continued gas availability will provide for the utilization of another $90 billion of consumer investment in appliances, furnaces and other gas consumer equipment.
- From the consumers' perspective, providing for the major residential and commercial energy needs of space heating, water heating, cooking and clothes drying, coal gasification will cost less than delivering these services with coal-generated electricity.
- From a national perspective, equivalent amounts of end-use energy would entail significantly lower investment costs, requirements and environmental residuals than either a coal-fired electric or coal-to-liquids facility.[4]

High-Btu Gasification—Research, Development, Demonstration and Commercialization (RDD&C)

The successful operation of the Great Plains Gasification Project marks the first large-scale commercial production of SNG from coal in the world. The plant, using the dry-bottom Lurgi pressure gasification process with North Dakota lignite feed, has achieved production rates in excess of design values ahead of schedule. Valuable information on the behavior of the process has been obtained. In August 1988 the Department of Energy decided to sell this $2.1 billion plant to Basin Electric Power Cooperative. The Great Plains Plant converts North Dakota lignite to 140 million cubic feet/day of substitute natural gas which sells for about $4.25/MMBtu.

Although funding for research and development related to coal gasification, particularly for activities related to high-Btu gasification, has been significantly curtailed by industry, the U.S. Department of Energy and GRI, there are still several noteworthy activities in this area. The emphasis of current research is to develop processes which will significantly reduce the cost of SNG relative to the commercially available dry-bottom Lurgi process. This is appropriate at this time considering the current perception that SNG from coal will not be needed before the turn of the century.

Medium-Btu Gasification—RDD&C

Activity has been high in RDD&C of medium-Btu gasifiers. The ash-agglomerating fluid bed gasifier, the slagging Lurgi gasifier and the entrained bed gasifiers such as Texaco, Dow and Shell, are in use producing medium-Btu gas.

The Texaco process has been extensively tested at the Cool Water coal gasification plant in Daggett, California and at Tennessee Eastman facilities in Kingsport, Tennessee at a commercial scale (1000 TPD). Another commercial facility is in operation by UBE Industries, Ltd. in Japan. Smaller scale demonstrations have been conducted at TVA in Muscle Shoals, Alabama. The Cool Water facility utilizes the medium-Btu gas directly for IGCC electricity production. At Kingsport the gas is used to produce acetic anhydride and, at UBE, ammonia is produced.

Recently, the SAR consortium has built and operated an 800 tons/day coal capacity Texaco plant at the Ruhrchemie facility to produce synthesis gas for chemicals. Two more Texaco plants are now under construction in China. The plant near Beijing will process about 800-1,000 TPD of coal while the second plant in the Shandong Province will have a capacity of about 600-700 TPD of coal.

Rheinische Braunkohlenwerke AG, near Köln, Federal Republic of Germany, has obtained extensive process performance data on the high-temperature Winkler Process, in a demonstration plant of 600 TPD coal capacity. The medium-Btu, pressurized (350 psi), entrained, dry ash discharge process has obtained extensive process performance data with lignite for synthesis gas production as well as for combined-cycle power generation.

Shell Development Company developed a pressurized (350 psi), entrained, slagging medium-Btu gasification process first in 1976 in a 6-TPD process development unit in Amsterdam, Netherlands; in 1978 in a 150 TPD unit in Hamburg, FRG, and now in a 250-400 TPD demonstration plant in Deer Park, Texas. The demonstration plant is obtaining process performance data with Illinois No.5 coal.

The Dow Syngas plant, at Plaquemines, Louisiana was commissioned in mid-1988. The medium-Btu gas, entrained slagging gasification process is tested with subbituminous coal and lignite at feed rates up to 2,900 TPD to evaluate cogeneration of power.

The Department of Energy has recently selected, under the Clean Coal Technology Program, an entrained-flow coal gasification process proposed by Kellogg and Combustion Engineering for a commercial-scale combined cycle power generation project in Illinois. At full capacity, the plant will be able to process 400 tons/day of coal.

Siting and Commercialization

More than 100 potential sites have been identified for high-Btu coal gasification facilities where coal mining, water and environmental issues do not present a constraint. Nevertheless, there are a number of institutional and economic factors which constrain the initiation of a coal gasification industry (high and medium-Btu).

Among these constraints are uncertainties associated with the outlook for supply, demand and price of conventional gas resources, the price of competing fuels at the time of first production, and the costs of compliance with existing and potential government regulations and laws. Even more important, the capital costs for a single commercial scale high-Btu plant are comparable to the net worth of the largest gas utility. From a prudent investor's viewpoint, not more than some 15 percent of net worth should be at risk in any one investment. As a consequence, no single company can construct a plant without relying on "project financing" (i.e., where the risk would be borne by the project itself without recourse to the credit capacity of existing businesses). Because of the scale of these projects and the regulatory/economic uncertainties, potential lenders thus far have required that some form of debt guarantee (either by consumers through an all-events tariff or by the federal government with a loan guarantee) be a part of the financing package for at least the first few plants.

Medium-Btu gas can be economically transported over distances up to 200 miles (depending upon the specific site). This makes it suitable for use in heavily industrialized areas where several potential industrial customers are located in close proximity.

In order to accelerate development of coal gasification in the United States, government efforts to reduce regulatory and commercialization risks must be forthcoming. This includes government support, not only in terms of R&D funding but, just as importantly, for protection against costly regulatory delays, reliability of reasonable environmental requirements and provisions for loan guarantees.

Several federal risk-sharing programs have been proposed over the last five years to reduce many of the initial commercialization uncertainties and risks to a level acceptable for private financial sector participation in high-Btu coal gasification. Energy prices have fallen dramatically in the last few years, and the energy supply outlook has greatly improved. As a result, the federal government has become very reluctant to provide financial assistance to commercial-scale synthetic fuels projects.

SNG From Liquid Hydrocarbons

The processing of liquid hydrocarbons such as naphtha, natural gas liquids (NGL), or liquefied petroleum gas (LPG) to produce substitute natural gas (SNG) is a known commercial technology that has been used in the U.S. and foreign countries for many years. In the U.S., the term SNG has become closely identified with facilities constructed by utilities in the 1970s for the production of SNG from naphtha, NGL's, and LPGs,[5] either as a base load system or as a seasonal peakshaving supply source.

Fourteen U.S. facilities achieved operational status during the 1970s. Processes used by these facilities are the British Gas Corporation Catalytic Rich Gas Process (CRG), the Lurgi Gasynthan Process and the Methane-Rich Gas Process (MRG), developed by the Japan Gasoline Company. The basic function of these processes is the conversion of feedstock inputs into a methane-rich gas suitable for combining with natural gas in a pipeline.[6]

A.G.A.'s gas utility industry self-help surveys[7] conducted for the 1976-77 and 1977-78 heating seasons showed that SNG was an important supply source in meeting gas demand. The National Energy Plan also noted this fact, stating that "the 13 SNG plants that were operating this winter (1976-1977) provided the additional margin of natural gas supply that kept several areas of the country from shutting off residential users during the coldest months." [8] This additional source of supply during the peak heating season has proved important for maintaining distribution system operating flexibility, particularly in those geographic regions in which existing plants are located.

Forecast and Rationale

The production and marketability of pipeline quality coal gas will be determined by a large number of interrelated factors, including the investment capabilities of the gas transmission and distribution companies, availability of investment assistance, the price of alternatives, industrial demand for this environmentally benign gaseous fuel, and the direct use of coal and petroleum products and conservation. There is, indeed, a strong likelihood that, to the extent there is growth in medium-Btu gas production, it will in part be determined by the growth in pipeline quality high-Btu gas production as these synthetic resources compete for markets and investment dollars. Ranges of estimates (Table VII-1) for total coal gas production between now and the year 2010 are based on the assumptions discussed on the following page.

TABLE VII-1

Production Estimates for SNG and Coal Gasification

(Bcf)

Year	Low Price Scenario	Middle Price Scenario	High Price Scenario
1995	53	53	53
2000	53	53	53
2010	53	53	100

The current excess gas deliverability situation has significantly dampened the interest in many supplemental supply sources, especially in the near term. Thus, it appears that high-Btu coal gasification supplies are not needed to supplement U.S. gas supplies in this decade. Nevertheless, most conventional gas supply forecasts (see Section IV) show a clear and growing role for supplemental gas sources beyond 1990.

High-Btu coal gasification is a purely domestic resource and, therefore, should play a role in the supplemental gas supplies of the future. Experience gained from the Great Plains project can be valuable in launching in the future a more significant coal gasification industry in the United States.

At the present time the prospects and economics for new SNG plants are very limited. In past studies, determinations of the potential for SNG production relied heavily on the anticipated availability of NGL feedstocks. Now, future production estimates are based on the relationships between the cost of feedstocks for SNG production, the price of natural gas from other sources and prices of competing fuels such as residual fuel oil. Because of these relationships, it is unlikely that SNG feedstocks will become available at prices low enough to allow SNG to compete on a widespread basis with other sources of gas.

Many of the existing SNG plants have been, or will soon be, mothballed. Several plants, including the one in Hawaii, could remain in operation, but annual production levels are likely to fall well below the 1987 production level of 14.8 Bcf.

As shown in Table VII-1 for the High Price Scenario, the experience from the Great Plains project and the anticipated trend in lower-48 gas supplies could, by 2010, result in the construction of another "Great Plains" size plant.

For the Low Price and Middle Price Scenarios, it is expected that only the Great Plains Plant and one or two SNG plants will be in operation throughout the projection period.

Footnotes

[1] Coal or carbon reacts with steam (H_2O) at high pressure to produce methane (CH_4), carbon monoxide (CO), and hydrogen (H_2).

[2] CO reacts with H_2O to produce $CO_2 + H_2$; the H_2/CO ratio is optimized for the methanation step.

[3] H_2 reacts with CO to produce CH_4 plus H_2O.

[4] For a detailed review of coal gasification technology and individual systems, see *Coal Gasification Technology Overview*, W. W. Bodle and F. C. Schora Institute of Gas Technology, 3424 S. State Street, Chicago, Illinois 60616.

[5] Definitions of these feedstock sources are:

Naphtha—Any of various volatile, often flammable liquid hydrocarbon mixtures used chiefly as solvents and diluents and as raw materials for conversion to gasoline and substitute natural gas (SNG).

Natural Gas Liquids (NGL)—These liquid hydrocarbon mixtures which are gaseous at reservoir temperatures and pressures but are recoverable by condensation or absorption. Natural gasoline and liquefied petroleum gases fall in this category.

Liquefied Petroleum Gas (LPG)—A gas containing certain specific hydrocarbons which are gaseous under normal atmospheric conditions, but can be liquefied under moderate pressure at normal temperatures. Propane and butane are the principal examples.

[6] W.L. Lom and A.G. Williams, *Substitute Natural Gas Manufacture and Properties*, New York, John Wiley & Sons, 1976.

[7] See articles in *Gas Supply Review*, July-August, 1977 and November 1976.

[8] Executive Office of the President, Energy Policy and Planning, *The National Energy Plan*, April 1977.

Section VIII

Nonconventional Sources of Methane

There are a number of resources from which future gas supplies will be produced as new technologies are developed, existing technologies are refined, and the economics for natural gas supply change. The gas industry has actively supported research and development programs designed to bring about the technological improvements necessary to foster production of these sources. Included in the nonconventional category are methane from biomass and waste, *in-situ* coal gasification, peat gasification, oil shale gasification (each of which involves a process whereby methane is produced from the conversion of solids) and methane hydrates, (which involves the production of gas from naturally occurring deposits). Also included in the nonconventional category is methane from landfills, production of which is already taking place on a limited scale. The sheer size of the resource base associated with each of the nonconventional sources continues to encourage research related activity for developing the technologies needed for methane recovery from these sources. However, with the strong near-term outlook for gas supply from conventional and other supplemental sources, progress in bringing forth methane production from the nonconventional sources is expected to be slow; thus, the focus on future production has shifted to the post-2010 period.

Biomass and Waste

The term "biomass," as used in this report, refers to plant matter grown and harvested specifically for the production of energy. A variety of crops is being examined for this purpose, including various grasses, plants, and trees in onshore locations, and kelp and other seaweeds in the oceans. "Waste" describes the organic byproducts, both animal and vegetable, which result from activities not specifically oriented towards energy production.

The production of methane from biomass and waste involves the use of processes which, through either anaerobic digestion or thermochemical conversion, convert solid (or liquid) organic material to a gaseous form which must then be processed to produce a high-Btu pipeline quality product. Numerous above-surface processes have been developed to convert biomass and waste; however, with few exceptions they have yet to demonstrate commercial applicability.

In certain geographic areas, the potential supply from these sources could be quite significant in terms of local energy needs. However, the widespread availability of conventionally produced resources has in recent years served to delay the development of biomass energy technologies. Nevertheless, there is industry-wide recognition of the tremendous potential which the biomass and waste resource represents. Thus, limited research and development programs needed to bring about production of this supply source continue.

Since the biomass and waste resources are renewable there are no limits to the amount of energy which can ultimately be produced from these sources. However, annual production levels will be limited and will depend on:

- the development of conversion technology which optimizes gas yield and reduces the need for large capital investment.
- the establishment of controlled cultivation systems which will produce commercially viable crop yields.
- the development of methods to process residuals into commercially valuable by-products.
- further development of harvesting, transportation and handling systems.
- methods of protection from diseases, insects and weather being established for biomass crops.
- changes in energy markets relative to the economics of energy production from biomass.

Environmental considerations, such as the need to dispose of digestor residuals or the impact of large-scale marine biomass farms, must also be further evaluated.

Of the several thermochemical biomass gasification processes that were developed, the pressurized (300 psi), fluidized-bed RENUGAS process developed by the Institute of Gas Technology is well suited for SNG production. A 12 tons/day process development unit was built and operated with Department of Energy funds at IGT during the mid-80s. The PDU obtained extensive process performance and environmental data on pulp wood chips, whole-tree chips, highway clippings, and bark-paper sludge mixtures.

Methane from Landfills

Among the techniques which have been developed to recover the energy in waste is the production of methane from landfills. Since its inception in the early 1970s, many projects have been developed across the country producing medium and high Btu gas. Medium Btu gas is typically used in a local industrial application whereas high Btu gas is pipeline quality and is generally directly linked to nearby distribution systems and provides a secure local supply of gas for the local utility companies. As of year-end 1988, there were eleven operational high-Btu facilities. Annual production from landfill recovery projects was about 2.5 Bcf of pipeline quality gas.

Landfill gas (LFG) is generated by the bacterial decomposition of organic materials contained in municipal solid waste (MSW). The rate of production and composition of the gas will vary depending primarily on the waste loading rate, the age of the landfill, the composition of the MSW and the moisture level.

Once deposition of the MSW has commenced and methane formation has started, the gas must be controlled and collected. Collection systems typically consist of a series of wells drilled into the landfill which are connected by a gathering system.

Extraction of the LFG is achieved by applying a vacuum to the system which withdraws the gas from the wells. It is important that air is not drawn into the landfill during this process as it will destroy the activity of the methanogenic bacteria.

The collection system transports raw LFG to a nearby treatment facility for upgrading. The amount of upgrading depends on the intended application for the gas. For high-Btu gas, most of the carbon dioxide contained in raw landfill gas (about 50 percent by volume), as well as all other compounds, except methane, must be removed. For both high- and medium-Btu applications, the gas must be dehydrated and compressed before injection into a pipeline. A distinct advantage of producing high-Btu gas is its ability to be transported through the existing distribution network thereby adding to peaking capacity.

Resulting from the ability to recover methane from landfills are a number of additional benefits. Among the most important are:

- A reduced hazard from uncontrolled accumulations of methane and capturing a usuable resource.
- The reduction of undesirable odors.
- Environmental advantages due to the reduction of reactive organic pollution problems and the destruction of vegetation which can result from gases migrating to the surface.
- Increased local energy supply security. LFG recovery provides a source of energy supply very near the eventual point of consumption. This increases the security of energy supply to the local community.
- Economic benefits to the local community from payment of taxes and royalties to the owners of the landfill (often city governments).
- Conservation of non-renewable fuels.

There are usually no severe technical limitations with respect to extracting and/or delivering landfill methane to meet individual customer needs and efforts to further improve the technology are continuing. The limitations of this market are economic. The decline in the real cost of oil and gas, combined with an inability to substantially reduce the cost of constructing and owning such facilities, no longer make them competitive with other incremental sources of energy. Thus, it is unlikely that additional plants will be built in the near term except for environmental reasons whereby the uncontrolled generation of methane from these sources present a safety hazard or are determined to be a significant contributor to free methane in the upper atmosphere. In the longer term, economics may again be favorable. Existing plants with long term contracts are likely to remain operational.

In-situ Coal Gasification

Much of the nation's coal resource is located in deposits which are not minable with conventional mining techniques. However, recovery of the energy from these deposits may be accomplished through *in situ* coal gasification, that is, conversion of the coal to gas underground in the deposit where the coal is found. Gasification in surface facilities to produce high or medium-Btu gas has been studied in great detail and thus much is known about the gasification process. (See Section VII.) *In-situ* coal gasification relies on essentially the same chemical processes as surface gasification; however, because the coal is not mined, *in-situ* gasfication does not require the relatively expensive mining and coal handling systems required in a surface facility.

Current estimates of the U.S. coal resource which is not recoverable by mining range upwards to 1.8 trillion tons. If only a fraction of this coal were recoverable by *in-situ* gasification, it would provide significant gas production. For instance, if 5% of the identified resource was found to be recoverable, it would translate to about 500 Tcf of methane—over two and one half times the current proved gas reserves level.

In-situ coal gasification has the potential to significantly expand economic extraction from coal seams which are too deep, too steep or too thick for conventional mining methods. In underground coal gasification, burning is initiated at a primary bore hole, and the product gas flows through a physical linkage to another bore hole for recovery.

Although gasification of coal in-place simplifies some aspects of the conversion process, a variety of technical questions must be answered before significant amounts of gas can be economically produced. In addition, there are environmental uncertainties associated with underground coal gasification: subsidence causing aquifer disruption, water quality effects caused by contamination of ground water with organic and inorganic materials, surface disruption, water usage, possible health and safety problems, and waste and atmospheric emissions.

Development of *in-situ* coal gasification continues to emphasize oxygen-blown operation with subbituminous coals. Successful tests were conducted by Gulf Oil Company at Rawlins, Wyoming in 1981 in a steeply dipping coal seam. This 60 day test produced medium-Btu gas with methane contents of up to 22 percent and a resultant heating value of 350 Btu/SCF.

Lawrence Livermore National Laboratory conducted a 30 day in-situ test at Centralia, Washington in 1983. This test constituted the first large scale evaluation of the controlled retracting injection point (CRIP) concept, which is a promising new method of controlling the underground cavity growth process.

In late 1987, the U.S. Department of Energy and an industry consortium, led by the Gas Research Institute, conducted a large-scale underground coal gasification (UCG) test. The test was successful and ran for 102 days.

Energy International's proposed Rawlins UCG project, a first solicitation winner in DOE's Clean Coal Technology Program, could be the first commercial scale UCG project in the U.S. At present, the company is finalizing the financial arrangements for the project. UCG projects are at various stages of development in Brazil, India, Yugoslavia, West Germany and New Zealand.

Peat Gasification

Peat, geologically the youngest form of coal, consists of partially decomposed vegetation which has been deposited in bogs at the land surface where moderate to high rainfall and partial isolation from local drainage systems create anaerobic conditions. As a result, peat occurs at the ground surface with little or no overburden material.

The peat resource base is less well defined than other fossil fuel resources, although enough is known about certain areas to justify planning for future gas production. Peat resources in the United States, excluding peat in permafrost areas, represent a potential energy resource of over 1400 quads.

In its natural state, peat may contain over 90 percent water by weight. In order to use peat as a fuel or for gasification, the bulk of this moisture must be removed. In Europe and the U.S.S.R., where peat is commercially used as fuel in power plants as large as 730 megawatts, peat-harvesting technology that incorporates air-drying in the drained bogs is widely used. Such techniques, however, are not very attractive in many peat-rich regions in the United States. Development of novel and economical techniques for dewatering peat is critical to its use as a resource for SNG production.

The gasification of peat to produce low-Btu gas has a history that goes back more than a hundred years. Peat gasification has been conducted on large scales in many different types of gasifiers. Commercial processes for the production of low-Btu gas from peat are offered by a number of manufacturers. It was only in 1978 that work was directed toward production of SNG from peat. Most of this work has been conducted in the U.S. at the Institute of Gas Technology (IGT) from laboratory through pilot-plant scale. This research has shown that, compared to coal, peat is more easily gasified and produces more methane, making peat a better resource than coal, on the basis of chemistry, for SNG production.

In late 1985, peat from Finland was successfully gasified by IGT at a rate of 1 ton/day in its U-Gas pilot plant for the production of medium-Btu gas. The medium-Btu gas produced can be upgraded by state-of-the-art processing to SNG.

A commercial-scale plant is nearing completion in Finland for converting peat to synthesis gas for ammonia production. The plant is capable of processing 650 tons/day of peat and uses the High-Temperature Winkler process for gasification.

Oil Shale Gasification

Oil shale is a fine-grained sedimentary rock containing an organic material known as kerogen. Vast oil shale resources exist in the eastern, as well as western, U.S. Estimates of western shale resources, mostly in Colorado, Utah and Wyoming vary from 420 billion to 1,230 billion barrels of oil equivalent in shales to a depth of 20,000 feet that contain over 30 gallons of oil per ton by Fischer-Assay. The Eastern shales are generally leaner than the Western shales. The estimates of the Eastern shale resources, primarily in Alabama, Indiana, Kentucky, Michigan, Ohio, West Virginia, and Tennessee, range from 400 billion to 2600 billion barrels of oil equivalent, depending upon the grade of shale included in the estimate and the recovery process used.

The processing characteristics of the two types of shale are different. Upon heating (retorting), the kerogen in shale decomposes to yield oil, gas, and residual carbon. The research conducted at the Institute of Gas Technology (IGT) has shown that retorting of shales in the presence of hydrogen at elevated pressures increases the yields of oil and gas. The improvement achieved by this approach is much more noticeable for the Eastern shales where carbon recovery of up to 2.5 times over that by conventional retorting can be attained. The raw shale oil is more like conventional petroleum than coal-derived oil, and can be further processed into liquid and gaseous fuels.

The recovery of oil from Western shales is at a more advanced stage of development. No particular technical problems exist with conversion of treated and refined fractions of shale oil to SNG. Some research and development work has also been conducted, primarily by IGT, for the direct production of SNG from Western, as well as the Eastern, oil shales.

In late 1983, pilot-plant scale (8 ton/hr) shale gasification tests were conducted in Sweden by Aktiebolaget Svensk Alunskifferutveckling (ASA) for the production of medium-Btu gas using a slagging gasifier. This technology should be applicable for processing other oil shales. Tests were conducted at IGT in 1987 with one Eastern shale in a Process Development Unit (450 lb/hr) to produce medium-Btu gas in a non-slagging fluidized bed system. Research is also being conducted to reduce the mineral matter content of oil shales prior to retorting. Technology developed to beneficiate coals is being applied to separate kerogen from the mineral matter in oil shales. Beneficiation of oil shale very significantly reduces the cost of shale conversion by IGT's hydroretorting process. Research programs are under way to produce medium-Btu gas from oil shale without using hydrogen and by in-situ gasification techniques using indirect heating.

A larger-scale pilot plant and demonstration plant operations are needed to verify the technical and commercial feasibility of converting oil shale directly to SNG.

Methane Hydrates

Methane hydrates are solid, ice-like compounds in which, under certain conditions of temperature and pressure, gas molecules are entrapped and bound with water molecules in a crystalline structure. It has been theorized that because conditions favorable to gas hydrate formation exist on a large portion of the earth's surface, significant accumulation of methane in gas hydrates may exist in deep ocean deposits and in permafrost areas onshore. These accumulations would include methane trapped in the gas hydrates themselves or possibly large quantities of gas trapped in the sediments below the impermeable gas hydrate layers.

Estimates of the resource for methane from hydrates are generally inferred based on theoretical knowledge about the conditions favorable for hydrate formation and the confirmed existence of hydrates in a number of locations. The limited amount of information results in estimates which are highly speculative; however, all estimates indicate an enormous resource—possibly as high as 6.7 million Tcf in the U.S. and 270 million Tcf worldwide.

Currently, there is no established production technology for recovering methane from hydrates although a number of concepts have been proposed. In general, these involve pressure reduction, temperature increase, and/or the addition of chemical agents to dissociate or "melt" the solid hydrate. An important consideration in the evaluation of production technology is the net energy balance; that is, assertaining if the energy recovered from the methane in the hydrate exceeds the energy input required by the production system. Given the low-permeability of hydrate-cemented sediments, the injection of fluids to "melt" the hydrates would be difficult. In addition, production systems may be required to handle the large amounts of water which would be released as hydrates are dissolved. Since much of the resource is located offshore, the problems unique to deep water drilling and production would also be a factor.

Given the current level of knowledge and the limited experience regarding methane hydrates, several major technological breakthroughs will be required before recovery of gas from this source can begin. Thus, commercial production is not expected to begin within the time frame of this report.

TABLE VIII-1

Nonconventional Sources Production Estimates

(Bcf)

Year	Low Price Scenario	Middle Price Scenario	High Price Scenario
1995	20	30	30
2000	40	50	75
2010	40	80	100

Production Estimates

Table VIII-1 presents estimates of future production for the nonconventional sources under the Committee's three scenarios. Given the considerable technology development required for the nonconventional sources, the 1995 estimate in each case primarily reflects landfill methane production. However, by the year 2000, the provision of needed federal support for nonconventional resource development could result in additional production from the other nonconventional sources. The Low Price Scenario estimate reflects lack of federal support and other conditions which in general do not encourage nonconventional resource development. Landfill gas development, particularly medium-Btu, would continue in this case, although growth would be limited. In the Middle and High Price Scenarios, the range in the production estimates reflects the varying results of early attempts to develop gas production from the other nonconventional sources.

It should be noted that the most promising period for growth in the production of the nonconventional sources is expected to occur outside of the time horizon of this report. The estimates presented here reflect the results of early efforts to develop these large resources. After 2010, these sources could contribute significantly to gas supplies as the results of current and near-term research and development efforts are implemented on a larger scale.

Section IX

Perspectives on Future Gas Supply

The Gas Supply Committee has analyzed natural gas supplies ranging from domestic production to imports to nonconventional sources of methane. This report describes each source in some detail including estimated amounts of available resource and estimated production potential. Tables IX-1, IX-2, and IX-3 quantify the volumes of gas that might be available from these sources through 2010 for each of the energy price scenarios. The diversity of supplies is still dominated by domestic production. Indeed, it is likely that 85 percent or more of U.S. gas supplies will be furnished by domestic sources in 2010.

Imports are not expected to exceed 14 per cent of the total supply mix, under any price assumptions and Canadian gas will account for more than 70 percent of gas imports. Currently, Canadian gas accounts for nearly all gas imports to the United States. However, LNG appears poised to capture an increasing share of the import supply mix given appropriate market opportunities and competitive pricing. New LNG purchase arrangements and plant restarts in 1988-1989 are evidence of this trend.

Another factor influencing the flow of supplies is that of pipeline capacity. To insure delivery of supplies to markets, pipeline systems must adjust, balancing producing regions with areas of gas consumption. The U.S. Northeast, for example, stands poised for expansion of natural gas services for utility and electric generation purposes. Two pipeline projects consisting of over 750 miles of new lines and costing a combined $880 million will supply nearly a billion cubic feet per day of new incremental volumes to the region by 1992 if regulatory and economic considerations allow them to do so. The gas supplied will originate from domestic and Canadian sources. Indeed, Canadian pipeline companies are also focusing on expansion projects to meet export needs in the near-term and long-term, for the U.S. Northeast, Midwest and West Coast areas.

In 1988, Canadian exports to the United States totaled nearly 1.3 Tcf. Most analysts believe that exports totaling 1.5-1.8 Tcf could be supported by the current pipeline infrastructure with minor additions to current pipe in place. However, export levels greater than 1.8 Tcf would require significant increases to pipeline capacity connecting Alberta with export points in central and eastern Canadian border areas. Another incremental increase in pipeline construction would be required for exports to reach 2.5 Tcf or greater. Such levels of exports are about 80 percent greater than those anticipated in 1989. Certainly, major additions to the Canadian pipeline infrastructure would be necessary to carry these volumes in the year 2010.

Alaskan supplies of natural gas to the lower-48 states will become a reality when the combination of foreseeable demand, pipeline engineering techniques and economics are in place to support the approximately $14.6 billion investment (as proposed by Foothills PipeLines for the Alaska Natural Gas Transportation System) necessary to complete the pipeline. Of course,

TABLE IX-1

Gas Supply – Low Price Scenario
(Tcf)

	1995	2000	2010
Oil Price Assumption ($1988/bbl)	18	22	33
Gas Price Assumption ($1988/MMBtu)	2.33	3.03	4.84
Lower-48	15.0	15.0	15.0
Imports			
Canadian	1.7	1.8	1.8
Mexican	—	0.1	0.1
LNG	0.2	0.35	0.6
Alaskan Gas	—	—	0.8
Other Supplemental Sources Including SNG/Coal Gasification, Nonconventional and Smaller Volume Sources[1]	0.1	0.12	0.12
Totals	17.0	17.4	18.4

[1] Also includes propane air, refinery gases, coke oven gas.

TABLE IX-2

Gas Supply—Middle Price Scenario

(Tcf)

	1995	2000	2010
Oil Price Assumption ($1988/bbl)	20	27	40
Gas Price Assumption ($1988/MMBtu)	2.59	3.63	5.52
Lower-48	16.9	18.0	18.5
Imports			
Canadian	1.8	2.0	2.5
Mexican	—	—	—
LNG	0.35	0.6	0.8
Alaskan Gas	—	0.8	1.2
Other Supplemental Sources Including SNG/Coal Gasification, Nonconventional and Smaller Volume Sources[1]	0.11	0.13	0.16
Totals	19.2	21.5	23.2

[1] Also includes propane air, refinery gases, coke oven gas.

TABLE IX-3

Gas Supply—High Price Scenario

(Tcf)

	1995	2000	2010
Oil Price Assumption ($1988/bbl)	30	38	62
Gas Price Assumption ($1988/MMBtu)	3.62	4.59	7.48
Lower-48	17.5	18.8	19.5
Imports			
Canadian	1.8	2.0	2.5
Mexican	—	—	—
LNG	0.5	0.8	0.8
Alaskan Gas	—	1.2	1.2
Other Supplemental Sources Including SNG/Coal Gasification, Nonconventional and Smaller Volume Sources[1]	.11	.16	.23
Totals	19.9	23.0	24.2

[1] Also includes propane air, refinery gases, coke oven gas.

evaluation of any such investment opportunity requires that a company be able to estimate performance of the gas market and product prices within that market. Past market and price volatility have made this a difficult task. As supply and demand balance and related economics become more predictable, projects designed to bring Alaskan gas to the lower-48 states will become increasingly viable in the 1990s and beyond.

Many expert observers believe that, with time, certain geographic areas of the lower-48 states will become more prominent producing regions as traditional areas, such as the Gulf Coast, decline. One such area is the Rocky Mountains. The Gulf Coast areas of Texas, Louisiana, Alabama and Mississippi, including the state and federal offshore, accounted for over 50 percent of the natural gas produced in the lower-48 states in 1987. However, the PGC estimates that only 30 percent of the remaining undiscovered resource base exists in the Gulf Coast region. By contrast, the Rocky Mountains accounts for 18 percent of the lower-48 resource estimate by the PGC, but was responsible for only 7% of the lower-48 gas production in 1987.

The Gulf Coast has an extensive pipeline network in place (though deep offshore discoveries will require additional pipelines), while the Rocky Mountains is much less developed in terms of gas transportation facilities. To reach the production potential reflected by its area resource estimate, pipeline infrastructure in the Rocky Mountain area may need to double by the year 2010.

Individually and cumulatively, each of the aforementioned pipeline additions will require considerable investment in dollars and materials for completion. Another aspect of future gas supplies requiring significant investments will be the recovery of domestic drilling as wellhead prices and economic conditions firm. Current gas completion levels of 7,500 wells per year cannot sustain a healthy domestic industry indefinitely. Increased opportunities for gas sales will undoubtedly spur drilling activity to stabilize gas production capability and will balance, in an economic sense, the various supply sources' contribution to the overall gas supply mix. The speed and aggressiveness of majors and independents alike in bringing crews, equipment, exploratory budgets and geologic prospecting back to levels more commensurate with 100 percent annual reserve replacements will depend upon individual perceptions regarding industry and economic trends. Willingness to assume the risks of expensive deepwater offshore plays and nontraditional onshore opportunities will be guided by industry's perceptions of the future of energy issues in this country.

Appendix A

Projected Energy Demand Studies

Brief Descriptions of the Five Major Energy Studies

- **U.S. Department of Energy (DOE)**, Energy Information Administration (EIA), *Annual Energy Outlook 1989-2000*, (1989).

  This study presents projections of energy supply, demand and prices. It examines several scenarios with assumed annual economic growth rates ranging from 2.4% to 2.5% out to the year 2000. In the year 2000, world oil prices per barrel (expressed in 1988 dollars) range from $21.70 to $35.00 with a base scenario price assumption of $28.00 per barrel. The base case also estimates total energy consumption of 90.6 Quads in the year 2000. Total energy consumption ranges from 88.6 Quads to 92.9 Quads for all scenarios in the year 2000. The gas share is 23% for all scenarios, with projected consumption of natural gas varying from 20.8 Quads to 21.2 in 2000.
- **Gas Research Institute (GRI)**, *1988 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, (1988).

  The GRI baseline projection is developed annually for planning within GRI and estimates future energy supply and demand. In the year 2000, the GRI baseline assumes a $27.03 per barrel world oil price (expressed in 1987 dollars) and annual economic growth rates ranging from 2.1% to 3.0% through 2010. In 2010, GRI estimates a total energy demand of 91.4 Quads with natural gas supplying 19.0 Quads or 21% of the total energy mix.
- **Energy Modeling Forum (EMF)**, Stanford University, *North American Natural Gas Markets, Volume II*, February 1989.

  The Energy Modeling Forum was established to provide a structural framework within which energy experts, analysts and policymakers could meet to improve their understanding of critical energy problems. The latest volume develops several energy scenarios based on key assumptions. For example, world oil prices in 2000 are estimated at $21.00 to $36.00 (expressed in 1986 dollars) depending upon the energy scenario developed. In addition, U.S. economic growth is estimated to average 2.6% to 2.7% annually through 2000. Total consumption of natural gas in 2000 varies from 16.14 trillion cubic feet (Tcf) to 19.84 Tcf depending on which scenario is modeled.
- **American Gas Association (A.G.A.)**, *A.G.A.-TERA 1989 Base Case*, (March 1989).

  The A.G.A. projection was based on an assumed oil price of $25.64 per barrel (1989 dollars) in the year 2000 and an economic growth rate of 2.4% annually through 2010. The result is a total energy consumption projection of 90.2 Quads in the year 2000 with gas contributing 21.7 Quads or 24% of the total energy mix.
- **Stewart, Marion B. (NERA)**, "The Gas Bubble: The End of the Consumer's Golden Age," *Natural Gas*, February 1979, pp.16-20.

  NERA (National Economic Research Associates) is an economics consulting firm in White Plains, New York. NERA anticipates slow economic growth, less than 15% growth in industrial gas pricing by 1995 and growth of 17% in gas well completions between 1990 and 1995 in the baseline forecast.

Appendix B

Terms and Conversions

The following are some frequently used units of measure and natural gas equivalents in British thermal units (Btu). Read "=" as "contains" between volumes and energy units.

The national average Btu content per cubic foot is used.

1 Cubic Foot (cf) = 0.02832 Cubic Meters = 1,031 Btu*
Cubic Meter = 35.315 Cubic Feet
1 Therm = 100,000 Btu ≅ 25,200 Kilocalories
≅ 100 Cubic Feet
1 Mcf = 1,000 Cubic Feet = 28.32 Cubic Meters
= 1,031,000 Btu*
1 MMcf = 1,000,000 Cubic Feet = 1,031,000,000 Btu
1 Bcf = 1,000,000,000 Cubic Feet
1 Tcf = 1,000,000,000,000 Cubic Feet
1 GigaJoule = 1,000,000,000 Joules; 1,000,000 Joules
= 947.8 Btu
1 quadrillion Btu (quad) = .9709 Tcf*

For comparative purposes, Btu contents of various energy sources other than natural gas are shown below.*

Fuel oil (barrel)	
Distillate	5,825,000 Btu
Residual	6,287,000 Btu
Coal (short ton)	
Bituminous and lignite	21,514,000 Btu
Anthracite	22,435,000 Btu
Electricity (kilowatt-hour)	3,412 Btu
Natural gas liquids (barrel)	3,804,000 Btu

*These values vary slightly from year to year. These values were reported by the Energy Information Administration, Department of Energy, *Monthly Energy Review*, November 1988.

Btu (British thermal unit)—the quantity of heat that must be added to one pound of water to raise its temperature one degree Fahrenheit from 58.5°F to 59.5°F, under standard pressure of 30 inches of mercury.

Butane (C_4H_{10})—a compound generally stored and delivered in liquefied form and used as a fuel in gaseous form, obtained by processing natural gas as produced and, also, from a process in petroleum refining. Contains approximately 3,260 Btu per cubic foot gas.

Coal gasification—a controlled process of reacting coal, steam, and oxygen under pressure and elevated temperature which produces low-Btu gas. Subsequent catalytic upgrading produces high-Btu pipeline grade gas.

Darcy—a measure of permeability. A permeability of one darcy means that the material will pass a fluid of one centipoise viscosity through a section of one cubic centimeter at a rate of one cubic centimeter per second with a drop in pressure of one standard atmosphere.

Distribution system—generally mains, services, and equipment which carry or control the supply of gas from the point of local supply to and including the sales meters.

Established reserves—reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgment portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.

FERC—Federal Energy Regulatory Commission.

FPC—Federal Power Commission, now called the Federal Energy Regulatory Commission.

Fracturing—a process of opening up underground channels in hydrocarbon-bearing formations, by force, rather than by chemical action such as in acidizing. High pressure is hydraulically or explosively directed at the rock causing it to fracture.

Gas, Associated—free natural gas in immediate contact, but not in solution, with crude oil in the reservoir.

Gas, Manufactured—a gas obtained by destructive distillation of coal, the thermal decomposition of oil, or the reaction of steam passing through a bed of heated coal or coke. Examples are coal gases, coke oven gases, producer gas, blast furnace gas, blue (water) gas, and carbureted water gas. Btu content varies widely.

Gas, Natural—a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geologic formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

1. dry—gas whose water content has been reduced by a dehydration process. Refers to gas containing little or no hydrocarbons, commercially recoverable as liquid product. Specified small quantities of liquids are permitted by varying statutory definitions in certain states.
2. wet—unprocessed natural gas or partially processed natural gas, produced from strata containing condensable hydrocarbons and water. The term is subject to varying legal definitions as specified by certain state statutes.

Gas, Non-Associated—free natural gas not in contact with, nor dissolved in, crude oil in the reservoir.

Gas from biomass—gaseous fuel which can be produced from vegetation by either thermal decomposition or anaerobic digestion; i.e., the biological breakdown of organic matter into methane and other materials by bacterial action in the absence of oxygen.

Gas from Devonian shale—natural gas produced from shale rock formations formed in the Devonian geologic era. This gas is produced principally in the eastern United States in Ohio, Kentucky, Pennsylvania, and West Virginia.

Gas Research Institute (GRI)—a not-for-profit membership organization of natural gas pipeline and distribution companies that plans, manages and develops financing for a research and development program designed to advance gas supply, transport, storage, and end-use technologies and to conduct related basic research *of mutual interest to the gas industry and its customers.*

Hydrocarbon—a chemical compound composed solely of carbon and hydrogen. The compounds having a small number of carbon and hydrogen atoms in their molecules are usually gaseous; those with a larger number of atoms are liquid and the compounds with the largest number of atoms are solid.

Hydrate—a solid ice-like material resulting from the combination of gas with water under certain conditions of temperature and pressure. Occurs in nature and in natural gas pipeline systems. Of natural gas constituents—methane, ethane, propane, isobutane, normal butane, and also hydrogen sulfide and carbon dioxide will form hydrates. Hydrates can cause restriction or stoppage of flow in pipelines and can be controlled by alcohol injection or by dehydration of the gas. Methane hydrates are found in some permafrost regions and beneath portions of the ocean floor, and may eventually be a source of gas supply.

Interstate pipeline company—a company which transmits materials by pipeline across state boundaries.

Intrastate pipeline company—a company which transmits materials by pipeline within state boundaries.

LNG (Liquefied Natural Gas)—natural gas which has been liquefied by reducing its temperature to minus 260°F at atmospheric pressure. It remains a liquid at –116°F and 673 psig. In volume it occupies 1/600 of the gas in the vapor state.

Methanation—catalytic upgrading of synthetic fuel gas to high Btu. Hydrogen and carbon monoxide react to form methane.

National Energy Act of 1978 (NEA)—a comprehensive energy statute comprised of five separate but intertwined public laws dealing with energy conservation, (The National Energy Conservation Policy Act, P.L. 95-619); coal conversion, (The Powerplant and Industrial Fuel Use Act, P. L. 95-620); public utility rates, (The Public Utility Regulatory Policy Act, P.L. 95-617); natural gas pricing, (The Natural Gas Policy Act, P.L. 95-621); and a series of taxes (Energy Tax Act, P.L. 95-618) designed to discourage energy consumption and to accelerate the transition to alternative fuels. The five bills were signed into law on November 9, 1978.

Natural Gas Policy Act (NGPA)—Public Law 95-621 signed into law November 9, 1978.

Natural gas proven reserves—proven reserves of natural gas are the estimated quantities of natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known natural oil and gas reservoirs under existing operating and anticipated economic conditions. Reservoirs are considered proven if economic production capability is supported by either actual production or conclusive formation tests.

Natural gas reservoir—a porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (gas and/or oil) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

Permeability—a measurement of the ability of a rock to transmit fluid.

Pipeline system—pipelines installed for the purpose of transmitting gas from a source or sources of supply to one or more distribution centers or large-volume customers, or a pipeline installed to interconnect sources of supply.

Porosity—voids in a reservoir rock available for storage of fluids. Measured in percent of rock volume.

Potential resources—hydrocarbon accumulations not yet confirmed by drilling or testing, however, believed to exist in concentrations of sufficient size and quality to warrant exploration and development. These hydrocarbon resources are judged to be recoverable given adequate economic incentives and utilizing current or foreseeable technology.

Propane (C_3H_8)—a gaseous member of the paraffin series of hydrocarbons, which when liquefied under pressure is one of the components of liquefied petroleum (LP) gas. Contains approximately 2,500 Btu per cubic foot (at 60 degrees Farenheit and 30 inches of mercury, and 91,740 Btu per gallon).

Proved reserves—the estimated quantity of hydrocarbon which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under anticipated economic and existing operating conditions. Reservoirs are considered proved that have demonstrated the ability to produce by either actual production or conclusive formation test.

RD&D—research, development and demonstration.

RDD&C—research, development, demonstration and commercialization.

Synthetic natural gas—a descriptive term used interchangeably with SNG and substitute natural gas.

Tight gas sands—gas-filled rock formations with low permeability.

Underground storage—the utilization of subsurface facilities for storing gas which has been transferred from its original location for the primary purposes of conservation, fuller utilization of pipeline facilities, and more effective and economic delivery to markets. The facilities are usually natural geological reservoirs such as depleted oil or gas fields or water-bearing sands sealed at the top by an impermeable cap rock.

Appendix C

Statistics

Year	Year-End Lower-48 Reserves[1] (Bcf)	Res. Adds[1] (Tcf)	L-48 GWC (000)	Lower-48 GW Footage (million)	Average Weekly Rigs[3]	Seismic Crew[4]	L-48 Prod.[1] (Tcf)	L-48[1] RLI	Total U.S.[1] Reserves (Bcf)
1988	—	—	7.72	42.8	937	189	16.28	—	—
1987	153,986	10.83	7.52	41.2	937	176	15.77	9.8	187,211
1986	158,922	14.69	7.89	41.5[2]	964	201	15.29	10.4	191,586
1985	159,522	12.21	14.10	71.1	1,980	378	15.67	10.2	193,369
1984	162,987	13.89	16.79	88.4	2,428	494	16.87	9.7	197,463
1983	165,964	14.96	14.28	75.8	2,232	473	15.52	10.7	200,247
1982	166,522	15.07	18.73	105.2	3,105	588	17.25	9.7	201,512
1981	168,693	21.56	19.91	106.7	3,970	681	18.50	9.1	201,730
1980	165,639	15.39	17.22	90.6	2,909	530	18.49	9.0	199,021
1979	162,977	13.73	15.17	79.9	2,177	400	19.69	8.3	194,917
1978	168,690	10.59	14.41	75.6	2,259	352	19.10	8.8	200,302
1977	177,046	11.76	12.12	63.5	2,001	308	19.26	9.2	208,878
1976	184,096	7.45	9.44	49.2	1,658	262	19.32	9.5	216,026
1975	196,149	10.14	8.17	44.5	1,660	284	19.56	10.0	228,200
1974	205,265	8.31	7.17	38.5	1,472	305	21.17	9.7	237,132
1973	218,308	6.51	6.98	38.2	1,194	250	22.47	9.7	249,950
1972	234,629	9.40	5.48	30.3	1,107	251	22.37	10.5	266,084
1971	247,441	9.44	3.98	23.4	976	221	21.92	11.3	278,805
1970	259,615	11.12	4.03	23.6	1,028	195	21.82	11.9	290,746
1969	269,907	8.34	4.08	24.2	1,194	263	20.64	13.1	275,109
1968	282,098	12.04	3.46	20.7	1,169	272	19.33	14.6	287,350
1967	289,273	21.09	3.66	21.6	1,135	278	18.36	15.8	292,908
1966	286,386	19.25	4.38	25.9	1,272	306	17.48	16.4	289,333
1965	284,484	21.16	4.48	24.9	1,388	354	16.24	17.5	286,469
1964	279,420	20.11	4.69	25.6	1,501	342	15.34	18.2	281,251
1963	274,460	18.10	4.57	24.5	1,499	331	14.54	18.9	276,151
1962	270,645	18.77	5.35	28.9	1,641	326	13.64	19.8	272,279
1961	265,352	16.35	5.49	29.3	1,761	380	13.38	19.8	266,274
1960	262,219	13.84	5.15	28.2	1,748	385	13.02	20.1	262,326

Source: Unless otherwise noted statistics are from the Energy Information Administration (EIA), U.S. Department of Energy.

[1] Prior to 1980 from A.G.A. Difference between 1979 and 1980 incorporates change from A.G.A. data to EIA data as reported in the EIA *Crude Oil, Natural Gas, and Natural Gas Liquids Reserves.* 1980 to 1988 production and total U.S. reserves as reported by EIA *Crude Oil, Natural Gas and Natural Gas Liquids Reserves.*

[2] API.

[3] Hughes Tool.

[4] Society of Exploration Geophysicists.

ENRON CORP'S OUTLOOK FOR NATURAL GAS
FUEL OF CHOICE FOR THE 1990's

EXECUTIVE SUMMARY

A year and a half ago, one of Enron's private consultants shared with us a very pessimistic forecast showing a dramatic contraction in U.S. supply over the next decade. To evaluate this prospect for ourselves, Enron launched an internal "bottoms up" evaluation of the U.S. supply outlook. The analysis involved reservoir engineers and geologists from our oil and gas company and our pipeline companies, as well as analysts from throughout the company. This paper presents the results of that effort.

Enron's estimate of the Lower-48 resource base (excluding Alaska) is roughly 650 Tcf, which is comparable in total to the 1988 estimate of the Potential Gas Committee (PGC). Our estimates vary regionally from the PGC's based on our own experience and evaluations. To perform the supply/demand evaluation, we used a comprehensive computer modeling system developed by Energy and Environmental Analysis, Inc. (EEA). The detailed supply model was built for the Gas Research Institute.

Base Case:

Under environmental legislation like that proposed by the President and consensus forecasts of world oil prices ($27/bbl in 1988$ by the year 2000), the U.S. gas market can grow to 19.2 Tcf by the year 2000 (excluding Alaska, which consumes 0.3 Tcf today). Two Tcf of new demand is created by electric utilities' needs to add new powerplants quickly and cost-effectively and environmental requirements for cleaner burning fuels.

Current Policy:

Without environmental reform, we expect the gas market to grow to 18.5 Tcf by the year 2000 under base case conditions.

Low Oil Prices:

If world oil prices are low ($20.50/bbl in 2000 in 1988 $'s), then the gas market is expected to contract to 1986 consumption levels by 2000 (16.5 Tcf under current environmental policy).

Low Drilling Costs:

If drilling costs escalate more modestly than in the base case (20% increase by 2000 instead of a 50% real increase), gas supplies could expand significantly to 20.9 Tcf in 2000. The sensitivity of our results to drilling cost assumptions underscores our conclusion that natural gas supplies are very sensitive to the producer's economics.

Results Across All Cases:

1. Under all scenarios, competition with residual fuel oil will become the major determinant of gas prices for the decade.

2. Under all of the scenarios, gas is competitive with coal on an "all-in" basis for new electric power generation.

3. Looking across cases, higher prices or lower costs elicit a significant supply response. This is an important result because the model looks at supply prospects the way a producer would--by calculating a return on their investment.

4. Competitively priced imports of Canadian gas and LNG play a growing role in the U.S. market, rising from 7% of today's supply to 13-15% in 2000.

5. The gas market experiences a period of tight supply before higher prices elicit a supply response. The gas market could experience a 2-5 year period of tight supply for the fuel switchable market until producers have an opportunity to respond to higher prices and increase deliverability again. This contraction only affects fuel switchable customers and does not shrink the gas market below 1986 consumption. The important result is that the resource base is big enough and the supply curve is elastic enough that supplies do respond over time.

I. INTRODUCTION

There is a fundamental contradiction in the way the gas industry is being portrayed these days. On the one hand, both observers of the industry and industry participants have begun to sound the alarm that natural gas is headed for a period of shortage:

John Sawhill, a director of McKinsey & Company, predicted gas shortages for the 1989/90 winter in the New York Times and in speeches.

> "The United States is vulnerable to another bout of natural gas shortages like the one we experienced in the 1970's...The decline in U.S. gas reserves threatens to bring on sharp increases in the price of that fuel." [1]

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[1] "When U.S. Wells Go Dry: Don't Count on Cooking with Gas", New York Times, 2/26/89.

> "Under a drastic scenario, consumption of natural gas could drop to the 13 Tcf range. It is difficult to see how the market could be much larger than 15 to 16 Tcf." [2]

Independent producers are also warning about impending shortages:

> "Producers have shut down drilling programs, laid off their senior and most experienced energy explorers, closed offices...We've seen over 1,000 independent producers go bankrupt." There is going to be a shortage of natural gas in the 1990's, he says, because the companies who go out and find that gas are not getting enough money to do the job. [3]

On the other hand, a recent report by the Federal Government's Energy Information Administration (EIA) touts the adequacy of gas supplies to meet growing demand:

> "By the year 2000, the United States may be using about twice as much natural gas to generate electricity as it does now. EIA has concluded that adequate gas supplies are likely to be available to meet additional gas demands that will be placed upon the system by such a rapid growth in gas-fired utility capacity." [4]

A year and a half ago, one of Enron's private consultants shared with us a very pessimistic outlook for future natural gas supply in the U.S. Concerned about this prospect, Enron's management directed the staff to take a good hard look at the future gas supplies over the long term. This white paper is based on work originally developed to respond to these internal management questions. However, as the study evolved, it became clear that the analysis could be very informative to the current public policy debate over oil imports and the environment.

The paper begins with a brief discussion of the assumptions and methodology Enron chose for our study. More technically interested readers may wish to read Appendix A which describes the methodology in more detail. Section III presents the study results under base case assumptions and alternative assumptions. Section IV contrasts Enron's results with the "hard landing" scenario posited by

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[2] Unpublished paper entitled "Putting the Gas Industry Back Together Again" presented to the Interstate Natural Gas Association of America's Security Analysts Conference, 8/89.

[3] "Anadarko Chief Foresees Gas Crunch", comments by Robert J. Allison, Jr., chairman of Anadarko Petroleum Corp., Houston Post, 2/5/89.

[4] "Electricity Generation from Natural Gas: Prospects and Implications for the United States", Energy Information Administration, U.S. Department of Energy, Washington, D.C., p. IX, SR/EPD/89-01, January 1989.

Mr. Sawhill of McKinsey & Company and to EIA's more optimistic outlook. The final section of the paper discusses the policy implications of the study.

II. METHODOLOGY & BASE CASE ASSUMPTIONS

Enron began its analysis of gas supply and demand realizing it needed an analytical framework, or modeling system, for determining the market equilibrium for all forms of energy over a wide range of scenarios. Of the several such systems available, we chose the Energy and Environmental Analysis, Inc. (EEA) Energy Overview Model. The EEA system solves for gas consumption and production, gas prices and drilling activity over time given inputs of crude oil prices, alternate fuel prices, the Lower-48 hydrocarbon resource base, regulatory environment, economic growth, etc.

A virtue of the EEA modeling system is the control it allows a user over all key assumptions and model parameters. This was important since Enron wanted to fold into the analysis its knowledge and understanding of the oil and gas business. Enron used a panel of reservoir engineers, geologists, economists, and gas marketers to check the key model parameters and develop the input assumptions for each scenario.

A second virtue of the EEA modeling system is the power of EEA's Hydrocarbon Supply Model--a rigorous, computer-based framework for analyzing the resource cost of finding, developing and producing natural gas and crude oil in the Lower-48 United States. The model and its supporting databases were developed for the Gas Research Institute in the early 1980s at a cost of over a million dollars. The databases contain information on all oil and gas fields found in the Lower-48 (outside Appalachia) through 1985--over 35,000 fields, as well as information on individual exploratory and gas wells and extensive data on leasing, drilling, equipping and operating costs.

Enron's natural gas outlook is based on a set of assumptions about the factors which drive U.S. gas supply and demand. Among these factors are economic activity, crude oil prices, exploration and development costs, the natural gas resource base, environmental regulations, powerplant construction plans, and the availability of LNG and Canadian gas.

Economic activity is a key driver of the demand for energy. For our analysis, we assume GNP and industrial output will grow 2.6%/year and 2.8%/year, respectively. The demand for electricity will grow 2.2%/year through 1995, and 1.9%/year from 1996 through the end of the century as higher electricity prices and tighter environmental regulations spur conservation measures.

Crude oil prices drive the search for hydrocarbons and directly influence the price of gas and the fuels that compete with gas. We assume the U.S. refiner's acquisition cost of crude will rise in line with world oil prices and reaches a price of about $27 per barrel (1988$) by 2000. During this time the price of lower sulfur grades of residual fuel oil will climb above crude prices as tighter environmental standards are imposed.

Exploration and development costs will increase in real terms as the level of activity in the oil and gas patch responds to higher prices. For our base case, we assume these costs increase 50% (in 1988$) over today's level by the late 1990s. Tempering this rate of increase is an assumed improvement of 10% in rig productivity.

The natural gas resource base is the major reason for the wide range of views concerning the future supply of natural gas. Enron's resource base estimate of 647 Tcf includes all conventional and nonconventional resources that are likely to contribute to supply over the next 10-20 years. This estimate is conservative only in the sense that we ignored resources that we believe require vastly higher prices or technological breakthroughs in order to be exploited.

Environmental regulations are likely to boost the demand for gas at the expense of other fuels such as coal and heavy fuel oil. For our base case, we assume that environmental legislation like the President's Clean Air Act Amendments are enacted. Such policies would enhance the economic attractiveness of gas versus residual fuel oil and lead to new uses of natural gas such as a fuel for private and commercial vehicles and co-firing and reburn in coal boilers.

Powerplant construction plans can have a major impact on future gas demand. If coal-fired plants are built, less gas will be used regardless of relative life-cycle costs. For our analysis, we assume all currently planned coal and nuclear fueled units enter service, but the great majority of unplanned plants are gas-fired combined cycle units. We have 33,000 MW of combined cycle capacity entering service between now and the year 2000.

LNG and Canadian imports can contribute significantly to U.S. supply over the next 10-20 years. Since the EEA Model does not solve for imports, the user must perform an offline analysis to determine appropriate import levels. We assume potential LNG imports grow from about 40 Bcf today to 380 Bcf in 1995 and 670 Bcf in 2000. The Canadian import potential grows from 1.3 Tcf in 1988 to 1.7 Tcf in 1995 and 1.9 Tcf by the end of the century. Import prices are assumed to be competitive with domestic supplies.

III. BASE CASE ANALYTIC RESULTS

A. Supply/Demand Balance

Under environmental legislation like that proposed by the President and consensus forecasts of world oil prices, the U.S. gas market can grow to 19.2 Tcf by the year 2000 (excluding Alaska which consumes 0.3 Tcf today). (See Table 1 and Figures 1 and 2.)

Table 1

LOWER-48 NATURAL GAS BALANCE [1]
Tcf

	1987	1990	1995	2000
DEMAND				
Residential/ Commercial	6.7	6.7	6.7	6.7
Industrial [2]	5.8	6.0	5.6	6.2
Powerplants [3]	3.0	3.0	3.5	4.1
Other [4]	1.9	1.9	1.9	2.0
Total Demand	17.4	17.6	17.7	19.0
SUPPLY				
Lower-48 Production	16.2	15.7	15.5	16.5
Canadian Imports	1.0	1.3	1.7	1.9
LNG+SNG+Supplementals	0.1	0.3	0.5	0.8
Total Supply	17.3	17.3	17.7	19.2

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[1] Excludes .3 Tcf of Alaskan Production and Consumption. Totals do not add up due to model convergence.

[2] Includes feedstock.

[3] Includes electric utility and cogeneration uses.

[4] Includes EOR, gas treating, liquids processing and pipeline compressor fuel.

During the forecast period, the gas market moves quickly from being demand constrained (as it has been for much of the 1980's) to being supply constrained. Deliverability declines modestly from 1989 to 1992, when higher prices begin to elicit a supply response. By 1995, gas production has returned to 1988 levels. During this 2 to 5 year period of tight supplies, fuel switchable customers in the industrial and electric utility sectors convert from gas to oil in order to balance the gas market. The gas supply contraction is mild; gas use never falls as far as 1986 consumption levels of 16.5 Tcf. One of the principal insights afforded by our methodology is that there are lags in the responsiveness of supply to price, but the response does occur over time.

Figure 1

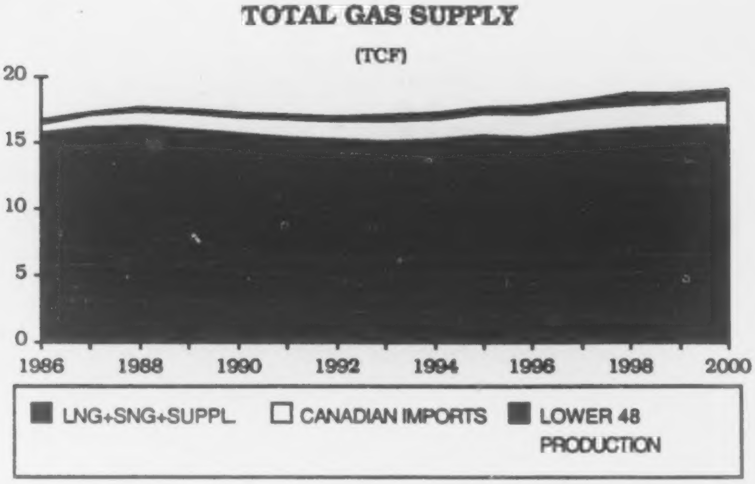
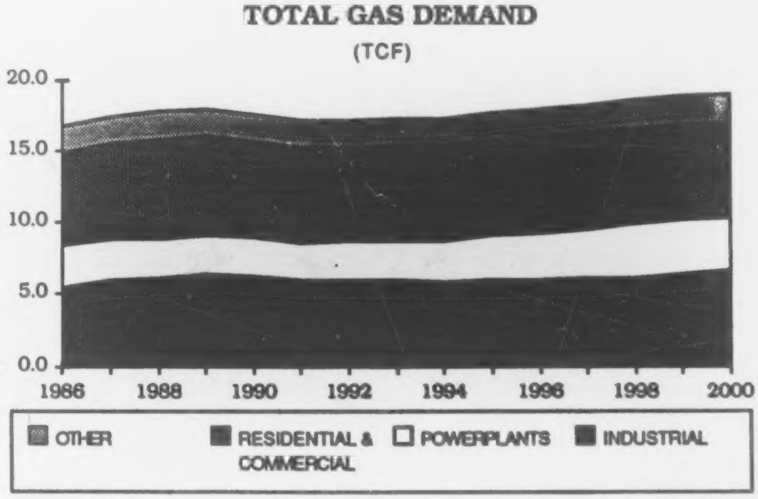


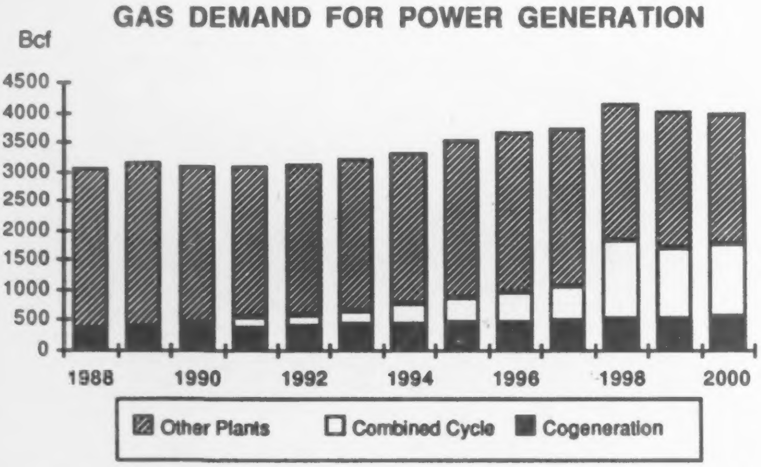
Figure 2



Throughout the forecast period, residential/commercial consumption stays relatively flat as demand growth due to market penetration into new households and buildings is offset by efficiency and conservation improvements in existing buildings as older equipment is retired and replaced by more efficient units. While our assumption of 170 Bcf increase in gas use in the commercial sector due to natural gas vehicles (NGV's) by 2000 is small on a national scale, introduction of NGV's could make an important contribution to solving the air quality problems of our nation's dirtiest cities.

The bulk of the gas market growth occurs in the powerplant sector where gas use increases by 1.1 Tcf over 1987 levels. More efficient technologies such as cogeneration and combined cycle units displace older, less efficient uses of gas in this sector over time [5] . (See Figure 3.)

Figure 3



Gas use in combined cycle units increases significantly in 1998 because we have assumed that all of the current utility plans to add coal and nuclear facilities do occur. Because the vast majority of these planned capacity additions are not gas fired, natural gas is not allowed to compete in new units until the late 1990's. In their first year of operation, each of the plants is assumed to operate as a base load unit.

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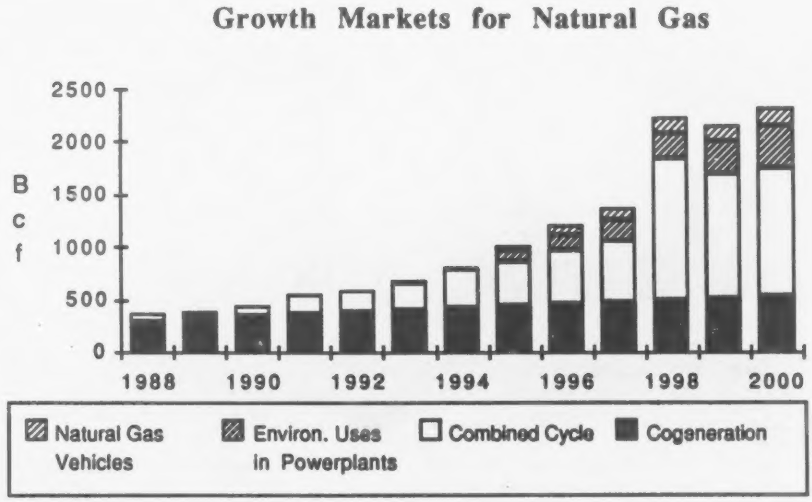
[5] For the purposes of this paper, cogeneration has been included in the powerplant sector, rather than in the industrial sector.

After its first year of operation, the model economically dispatches the unit. The slight reduction in gas use in combined cycles from 1998 to 1999 is because most of the units are dispatched as intermediate load rather than as base load. Our conclusion from this phenomena is that natural gas is very competitive in base and intermediate load applications.

As we will see in the pricing section, gas prices in the 1990's are still competitive enough to allow for the economic construction of gas fired combined cycle units in competition with new coal fired units--even before the passage of additional environmental restrictions. Over time, industrial gas demand is also "high graded"--going into the nonfuel switchable nonboiler applications. Finally, by 2000, 400 Bcf of gas is used in conjunction with coal for both environmental and efficiency reasons in the electric generation sector.

In summary, four growth markets--new highly efficient power plants, cogeneration, environmental uses of gas in combination with coal, and natural gas vehicles--add 2 Tcf of new, higher-valued demand over the next decade (see Figure 4). Most of this growth occurs after 1995 as new powerplants are built to meet growing electricity needs and as acid rain legislation requires pollution reduction.

Figure 4

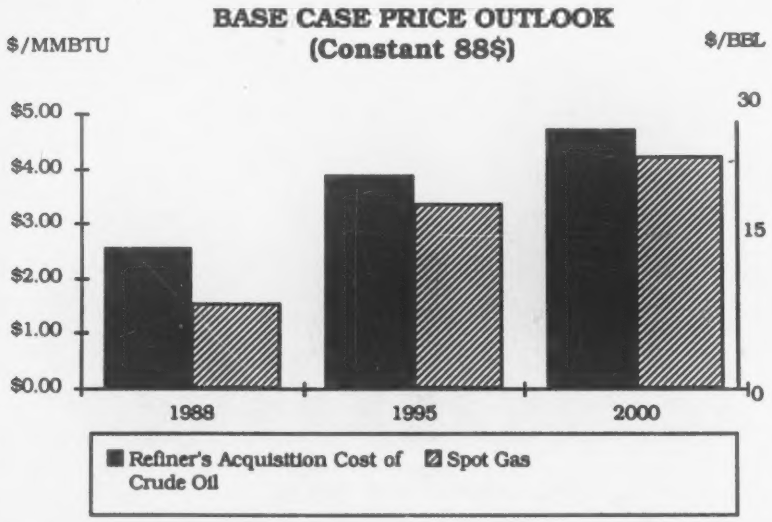


By the year 2000, price increases have restored Lower-48 production to current levels. Domestic supply contracts for a short period because it takes time for producers to add reserves and increase deliverability in response to higher prices. Canadian and liquified natural gas (LNG) imports grow from 7% of U.S. supply to 14% by 2000. At the prices forecast in these scenarios, it is economic to not only reopen all four U.S. LNG terminals, but to do the low cost expansions at the existing sites. The price outlook warrants incremental investments in pipelines from Canada, LNG tankers, and liquefaction facilities as well. We have assumed lower Canadian imports than the volume of current import projects being pursued. One could get to the same total outlook for U.S. supply and demand by assuming higher Canadian imports and lower LNG imports. Our conclusion is that there is a significant and growing role for competitively priced imports in the U.S. natural gas outlook.

B. Price Outlook

Over time spot gas prices, which today are selling at a deep discount to crude oil prices at the wellhead, rise relative to oil prices. (See Figure 5.)

Figure 5



As the gas market becomes supply-constrained (instead of demand-constrained), competition with residual fuel oil in the industrial and electric utility sectors becomes a major determinant of gas prices. Three additional factors lead to a closer Btu parity between crude oil and natural gas at the wellhead. First, by 1995 acid rain legislation provides natural gas with a modest premium over higher sulfur fuels, such as residual fuel oil. Second, by 2000, customers are burning lower sulfur content resids to comply with tighter environmental restrictions. Thus, lower sulfur resids rise in price relative to crude oil. Finally, pipelines and local distribution companies are assumed to either discount their rates to hold the incremental fuel switching load or to establish seasonal rates along the lines of the recent FERC policy statement on rate design.[6] The EEA modeling system can be run on a variety of regulatory and behavioral assumptions about rate design and discounting. We assumed regulators would not discourage recent trends towards discounting. Gas demand at these wellhead prices would be somewhat lower if discounting and rate reform were not assumed.

By 2000, spot gas prices rise to $4.40/MMBtu (1988$)[7], under base case oil price assumptions. This forecast is heavily influenced by the price path assumed for world oil prices which rises smoothly to reach $27/bbl (1988 $'s) by the year 2000. While these increases to producers produce a significant drilling incentive, the impact on consumers is much more modest because consumers also pay for transmission and distribution costs, which are not expected to change much over the period. In terms of the consumer, gas prices will increase by roughly 25% for homeowners above inflation from 1986 to 2000. This forecasted price increase is comparable to residential gas price increases over the previous decade. Competition between natural gas and residual fuel oil sets the market clearing price for gas in the forecast period. Since the results are highly sensitive to oil price assumptions, and future oil prices are highly uncertain, a low oil price scenario was run as a sensitivity case (see Section D).

By 1995, price levels have risen sufficiently (to $3.50/MMBtu in 1988 $'s) that the reopening of the U.S. LNG terminals is economically justified. These price levels also justify significant increases in drilling efforts in the Lower-48 (discussed in the next section).

As discussed in the methodology section, the lag structure of the model means that it takes a while for higher prices to elicit a supply response. In the real world, the lag in supply response will depend on the extent to which producers drill in anticipation of price increases and the speed and efficiency with which the drilling service industry can expand.

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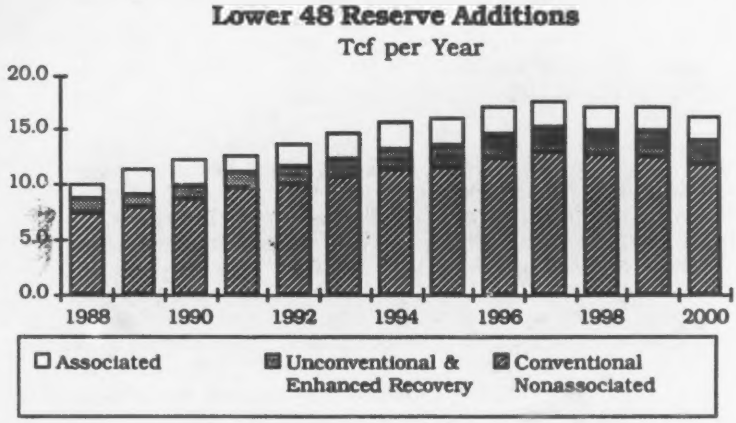
[6] Interstate Natural Gas Pipeline Rate Design _et al_ 47 FERC, paragraph 61, 295 (1989).

[7] All prices in this paper are in 1988 dollars unless otherwise noted.

C. Reserve Additions/Capacity Utilization

Forecasted domestic reserve additions grow from 10 Tcf in 1988 to 16.2 Tcf in 1995 and peak at 17.5 Tcf in 1997 (see Figure 6).

Figure 6



Over time, unconventional gas and gas using enhanced recovery techniques provide a growing share of the reserve additions. Reserve replacement ranges from roughly 60% to 110%. For a seven year period from 1994 to 2000, reserve additions exceed Lower-48 production as producers respond to higher price levels. The model has features which attempt to capture the potential for technological improvement. However, this is one area where any analysis may be excessively conservative. For example, when Enron first ran the model in 1987, we used 5.9 Tcf for an estimate of the coal bed methane resource potential. Today, we are using 47.1 Tcf based on the impressive advances in recovery techniques in the last two years.

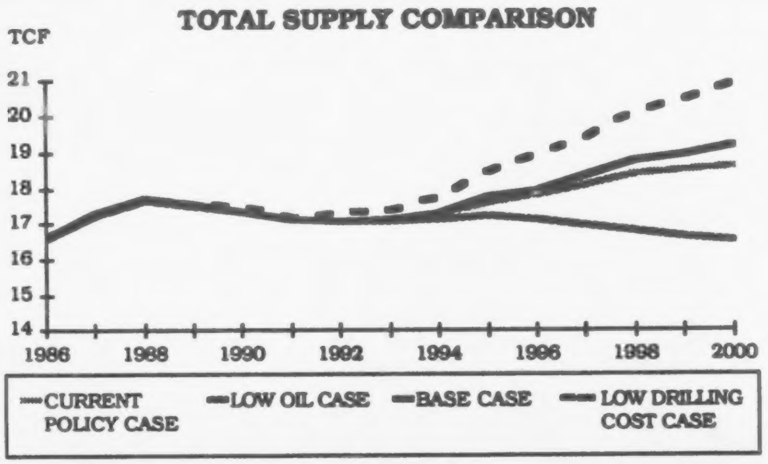
Another important factor is the increase in capacity utilization of deliverability from roughly 75% in 1986 to roughly 92-93% over the decade of the 1990's, which indicates an end to the "bubble". Capacity utilization rises to above 90% as storage absorbs more of the offpeak supplies and as interruptible customers experience interruptions in the winter. In essence, we forecast that the industry will operate at lower reserve-to-production ratios than in the past.

During the decade of the 1990's, the inventory of roughly 160 Tcf of probables is exploited preferentially because these resources are the easiest to find and develop. The drilling boom of the late 1970's and early 1980's left us with a "surplus" of probables, as well as a surplus of deliverability. By the late 1990's, we expect this probable surplus to be worked off. The drop off in reserve additions shown in 2000 occurs in part because the bulk of the probables have been found in the preceding decade. More optimistic forecasts, such as EIA's, assume that infill drilling, for example, provides a large inventory of inexpensive resources which can be found into the late 1990's.

D. Sensitivity Cases

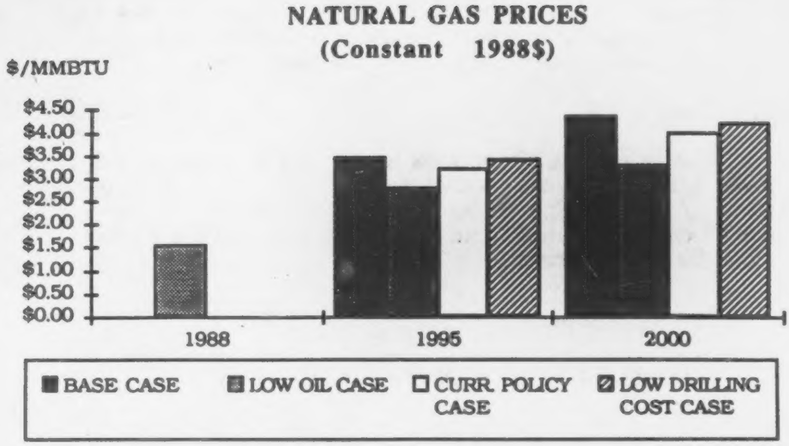
To test the sensitivity of our supply outlook to alternative assumptions, Enron ran three sensitivity cases varying environmental policy, oil prices, and drilling costs. The resource base evaluation was held constant across all cases. Figures 7 and 8 compare the total gas supply and price outlook for the four cases.

Figure 7



1. Current Policy: The Current Policy Case assumes no environmental reform is enacted and uses base case world oil price assumptions. Under this scenario, natural gas supply is lower by 0.6 Tcf by the year 2000 and gas prices at the wellhead are $.25-.40/MMBtu lower from 1995 to 2000. The bulk of the reduction in gas use is in the powerplant sector. This scenario demonstrates that natural gas supply can expand to meet new demands created by acid rain legislation and that the price increase as a result of that demand growth is quite modest.

Figure 8



2. Low World Oil Price Case: This case assumes oil prices reach $20.50/bbl by the year 2000 compared to $27.00/bbl in the base case. This oil price scenario is at the low end of the range of forecasts we reviewed. This case also assumes current environmental policy. Low oil prices increase the intensity of oil/gas competition in the industrial and electric utility sector. The gas market loses 2 Tcf of demand to oil among fuel switchable customers, thus increasing oil imports by roughly 1 MMB/D. Gas prices in 2000 are $.70/MMBtu lower than in the base case. Total consumption in 2000 is equivalent to 1986 consumption levels. This case demonstrates the sensitivity of gas supply to price.

3. Lower Drilling Cost Case: As described in Section II, Enron's base case assumed a 50% real increase in drilling costs over the decade. While it is clear that prices for drilling rigs and other factors in exploration and production are depressed below replacement costs today, future price levels for these services are highly uncertain. Because producers incur these costs up front, their economics are heavily influenced by expected future costs. As a sensitivity case, we assumed drilling costs increase 20% (in real terms) over the period. By 2000, this cost reduction increased supply by 1.8 Tcf compared to the base case. This sensitivity case underscores a basic conclusion of our study: higher prices or lower costs elicit a significant natural gas supply response. This is an important result because our analysis looks at supply prospects the way a producer would--by calculating a return on investment.

E. Results Across All Cases

Reviewing the four sensitivity cases Enron ran, six major points emerge.

1. Under all scenarios, competition with residual fuel oil will become the major determinant of gas prices for the decade.

2. Under all of the scenarios, gas is competitive with coal on an "all-in" basis for new electric generation.

3. Looking across cases, higher prices or lower costs elicit a significant supply response.

4. Competitively priced imports of Canadian gas and LNG play a growing role in the U.S. market, rising from 7% of today's supply to 13-15% in 2000.

5. The gas market experiences a period of tight supply before higher prices elicit a supply response.

   - The gas market could experience a 2-5 year period of tight supply for the fuel switchable market until producers have an opportunity to respond to higher prices and increase deliverability again. This contraction only affects fuel switchable customers and does not shrink the gas market below 1986 consumption levels. The important result is that the resource base is big enough and the supply curve is elastic enough that supplies do respond over time.

6. With our resource base evaluation, it is highly improbable that gas deliverability would contract so rapidly that we would see a 13 Tcf market in the U.S. in the next decade as suggested by John Sawhill of McKinsey.

IV. COMPARISON WITH OTHER OUTLOOKS

As indicated in the introduction to this white paper, some industry observers and participants are predicting that the gas industry could experience a "hard landing" in the next year. By this they mean a sustainable and dramatic increase in natural gas prices and a shortage of gas like in the 1970's. Others in the industry lament the low levels of drilling and correctly observe that natural gas prices are below replacement cost. They express concern over whether the industry can gear up quickly enough to respond to rising prices once we have worked off our surplus deliverability.

Over the longer term, there are both optimists and pessimists about the future size of the natural gas markets. While a number of analyses can be characterized as "optimistic", we have chosen the EIA forecast of a 21 Tcf market by the year 2000 as representative of this group. [8] Because EIA is very disciplined about explaining their resource base assumptions, their study makes comparisons with our own analyses more transparent. Similarly, while a number of analyses can be characterized as pessimistic, we have chosen a McKinsey study as representative of this outlook. The McKinsey study forms the basis for the John Sawhill quote cited in the introduction of this paper suggesting that the gas market could contract dramatically to 13 Tcf. Both studies were chosen because they represent frequently cited outlooks by respected analytical organizations.

In this section we will first discuss the likelihood of a "hard landing" and then compare our longer term results to EIA's and McKinsey's.

A. The Short Run Outlook: Is A Hard Landing Likely?

Enron's results do not support the "hard landing" scenario. The "hard landing" hypothesis depends on the premise that neither supply nor demand is very price responsive in the short run. Throughout the next decade, our forecasts show a large volume of gas being consumed in dual fuel capable boilers which can switch to oil as gas supplies tighten. Enron anticipates that during the peak winter heating season, interruptible customers with dual fuel capacity will switch to alternative fuels. This "tight supply" scenario is quite different from a "shortage" where high priority residential/ commercial customers literally cannot obtain adequate supplies. Even if low gas prices have lulled fuel switchable users into letting their oil burning capability deteriorate, or into not stockpiling alternative fuels during the winter months, the periods of tight supply last winter should have been ample warning for these interruptible customers to prepare better for this winter. Even so, a lack of preparedness will last only one season in the unlikely case that John Sawhill's forecasts of supply shortage do occur. The following winter, everyone will be ready.

On the supply side, we would agree that there are lags in the ability of the industry to respond to higher prices. Enron's analysis explicitly considers these lags. To test the reasonableness of our forecasted buildup in exploration and development activity, we calculated the buildup in rig activity implicit in our forecast (see Figure 9).

By the year 2000, we need double the active rigs (1900 instead of today's 900). The buildup is fairly gradual over the period. The E&P industry has expanded this quickly before. From 1971-1978, active rigs more than doubled from 890 to 2061. (And went on to triple in a decade by rising to 3690 in 1981.) While productivity certainly fell during the peak level of activity, we believe productivity would have improved even if prices had stayed high rather than collapsing in a boom and bust cycle.

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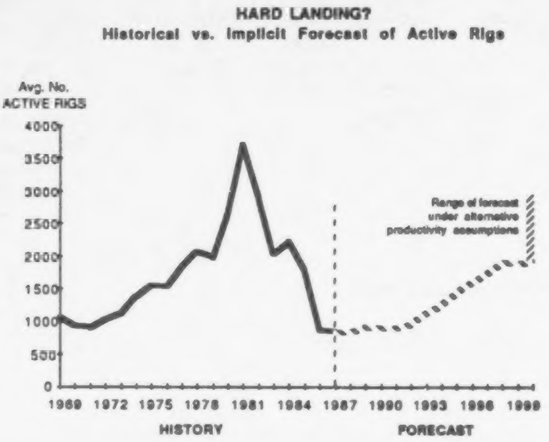
[8] EIA Report, IBID (see Footnote #4).

Figure 9



HARD LANDING?
Historical vs. Implicit Forecast of Active Rigs

Because our analysis allows the industry some time to expand drilling activity, our forecast shows a modest contraction in supply over the next three years of 0.6 Tcf. Deliverability falls off and the supply engine takes time to get started up again. However, our projected market, even in that tightest year, is still larger than in 1986. How tight the supply will be depends heavily on major uncertainties on the demand side as well--weather, the economy, performance of coal/nuclear plants in regions with a lot of gas-fired facilities, among other factors. But if producers see the price increases, our results show that the supply will be forthcoming.

Another part of the McKinsey "hard landing" story is that the institutions which have apparently performed well in a surplus market have a high potential for failure as gas supplies become tight due to deliverability declines. In particular, McKinsey is concerned that "the traditional relationships between suppliers and customers have all but broken down...If distributors are not going to extend contracts and commit to take gas, then the pipelines should be able to end any remaining service obligations." [9] Mr. Sawhill fears that distributors will call on their traditional supplier on a cold winter's day and find that the pipeline has shed its supply to minimize take-or-pay exposure.

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[9] Sawhill, New York Times, ibid (see Footnote #1).

While we agree with McKinsey's suggestion that the current regulatory environment encourages customers to rely excessively on spot gas, Enron believes that there is an important distinction between the institutional failures which led to the shortages in the 1970's and the need to complete the transition to a well-functioning gas market. Predictions of a 1970's style shortage ignore the real and important reforms Congress and the Federal Energy Regulatory Commission (FERC) have implemented in the natural gas market--principally wellhead decontrol and open access for pipelines. These regulatory reforms make the gas market far more flexible and responsive than the industry was in the 1970's. While Enron would argue that further reforms are necessary to have a well-functioning industry, we believe that the reforms to date are sufficient to prevent a 1970's style shortage. Section V discusses these proposed reforms in more detail.

B. The Longer Term Outlook: Comparison with the Optimists.

Over the longer term, the optimists view the electric utility sector as a key growth market for natural gas. For example, EIA forecasts a doubling of gas use in the electric utility sector by the year 2000 [10]. Under EIA's base case assumptions, the gas market grows to 21 Tcf by the end of the decade, with a range of outlooks from 19.3 to 23.3 Tcf. In contrast, Enron forecasts a 19.2 Tcf market in 2000, with a range of 16.5 to 21.9 Tcf. (See Table 2.)

Table 2

GAS SUPPLY COMPARISON
($/MMBTU, TCF)

ENRON CASES	1988		1995		2000	
	PRICE	SUPPLY	PRICE	SUPPLY	PRICE	SUPPLY
Base Case	$1.57	17.7	$3.46	17.7	$4.37	19.2
Current Policy	$1.57	17.7	$3.21	17.5	$4.00	18.6
Low Oil Prices	$1.57	17.7	$2.79	17.1	$3.29	16.5
Low Drilling Cost	$1.57	17.7	$3.41	18.4	$4.19	21.0
EIA	$1.63	17.8	$2.68	19.8	$3.79	21.0

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[10] EIA Report, IBID (see Footnote #4).

There are three key factors which cause this difference between Enron and EIA's outlooks:

1. EIA uses a resource base of 900 Tcf; 250 Tcf larger than Enron.
2. EIA's growth rate for electric demand is 2.6%/year through 2000; in contrast to Enron's lower growth rate assumption of 2.2%/year to 1995 and 1.9%/year thereafter. A higher growth rate gives EIA the opportunity for more new gas-fired units to enter the powerplant market.
3. Enron assumes a 50% real escalation in drilling costs over the period. EIA is not specific about their assumptions and may be assuming little or no real cost increases.

EIA's larger resource base assumption and apparently lower drilling costs mean that they forecast larger supplies at similar prices. In fact, EIA's base case is quite similar in 2000 to Enron's low drilling cost case (see Table 2).

The 250 Tcf difference in resource base assessment can be narrowed to three major areas. EIA is much more optimistic about the potential for additions to gas reserves from infill drilling (145 Tcf) and from low permeability resources (180 Tcf). Enron's experience in the huge Hugoton field (where more than 200 infill wells have been drilled on our system) does not support EIA's infill hypothesis. However, Enron does include some low permeability resources in its new fields and old field appreciation categories which together are about 60 Tcf higher than EIA.

Finally, EIA's estimate of the "low cost" resource base (recoverable at less than $3.00/MMBtu) is more than two and a half times larger than Enron's (424 Tcf vs. 160 Tcf). If EIA and Enron were to use the same assumptions about drilling costs, our assessment of the "low cost" resource base would be more similar than it appears from this data. For example, Enron's estimate of the low cost resource base rises from 160 Tcf to 235 Tcf in our low drilling cost scenario. With flat real drilling costs, Enron's low cost resource base would rise to 295 Tcf.

In conclusion, alternative assumptions about the size of the resource base, drilling costs and demand growth by electric utilities can lead to a more optimistic outlook for natural gas than Enron has forecast.

C. The Longer Term Outlook: Comparison with the Pessimists

We have chosen McKinsey's analysis as an example of a pessimistic view for three reasons: first, it has received a great deal of public attention; second, McKinsey's approach is typical in concept to other

Figure 10

STATISTICAL RESERVE ADDITIONS MODEL

ACTIVITY (FEET DRILLED)	X	YIELD (BCF/100,000 FT DRILLED)	=	RESERVES ADDED (BCF)

FUNCTION OF:	Marginal gas prices Cumulative reserves found	Activity Cumulative reserves found
FORM OF EQUATION:	LN (Activity) = X_0 LN (Price) + X_1 (Cumulative Reserves) + C_0	LN (Yield) = X_0 LN (Activity) + X_1 (Cumulative Reserves) + C_0

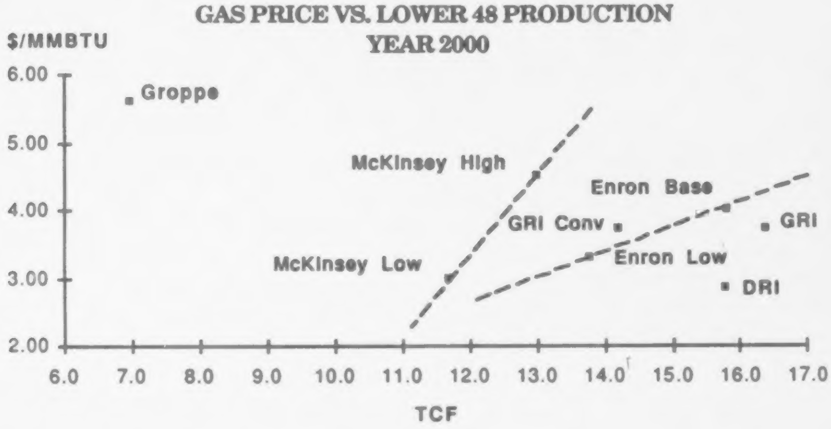
Source:	Reserve additions:	DOE/EIA U.S. Crude Oil, Natural Gas, and Natural Gas Liquids
	Feet drilled (successful gas feet):	API Quarterly Completion Report; Joint Association Survey (deep)
	Prices:	Natural Gas Week; DOE/EIA Natural Gas Monthly; DOE/EIA Interstate and Intrastate Supply Markets Under the NGPA
	Cumulative reserves found:	AGA Reserves of Crude Oil, Natural Gas, and Natural Gas Liquids in the U.S. and Canada

analyses which also forecast a pessimistic outlook; and finally, because McKinsey uses systematic and relatively accessible methods.

The McKinsey procedure is to estimate two equations with regression analysis. (See Figure 10.) First they estimate the relationship between drilling activity on the one hand, and the current level of gas price and cumulative reserves found on the other. Second, McKinsey estimates the relationship between finding rate (gas reserves added per foot drilled) on the one hand, and current drilling activity and cumulative reserves on the other. This pair of relationships is estimated for each of 20 regions. The data used are the prices, drilling activity, etc. for each of the 17 years from 1970 to 1986. Using projections of future price, McKinsey estimates future reserve additions by combining these two relationships.

In Figures 11 and 12 we compare McKinsey results with the Enron and other forecasts. Figure 11 shows production versus price in the year 2000 for a number of different projections.

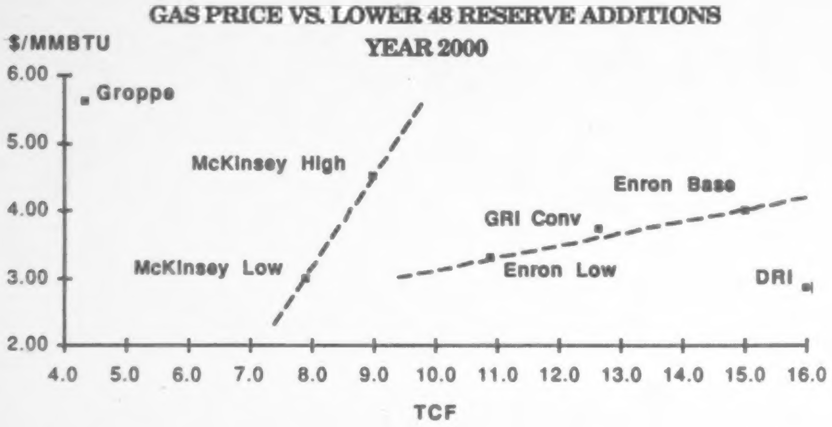
Figure 11



Sources: Groppe, Long & Littell, private client study, March 1987
McKinsey & Company, private client study, August 1988
Gas Research Institute (GRI), 1988 Baseline Projection, Dec. 1988
Data Resources Inc. (DRI), Natural Gas Review, Spring 1989

Figure 12 shows reserve additions versus price for the year 2000 for the same set of projections. Among this set of forecasts McKinsey projects less production and reserve additions at a given price than all but one other forecast. More importantly, McKinsey's results also show relatively little increase in production or reserve additions at significantly higher prices, compared to the Enron estimate.

Figure 12



In Enron's opinion this lack of supply response to higher prices is not realistic. McKinsey has obtained this result because their efforts to statistically identify long term trends were swamped by the drilling boom and bust of the early 1980s. (See Figure 9.) This period featured an "excessively" rapid build up in drilling activity, fueled by rising prices and the speculation of future price increases. In our opinion, this build up proceeded more rapidly than geologists and engineers in the industry could identify good drilling prospects. Consequently, the expanded drilling was relatively ineffective and statistical analysis based on this period tends to seriously underestimate the reserve additions which would result from a sustained increase in drilling activity.

While it is theoretically possible to disentangle long term trends from the speculative boom through more complicated econometric analysis, it is likely to be difficult to do so with only 17 years worth of observations. Enron believes that our emphasis on resource base analysis avoids these pitfalls.

In conclusion, Enron believes that McKinsey's methodology leads them to the inappropriate conclusion that the U.S. supply curve is quite inelastic.

V. POLICY IMPLICATIONS

Enron's study shows that natural gas is there (and can be drilled) if producers see the right price signals. While the gas industry has made tremendous progress since The Natural Gas Policy Act was passed in 1978, more reforms are needed before gas can play its full role.

1. The President's Clean Air Act proposal, with its "freedom of choice" environmental policy, goes a long way towards providing market incentives for cleaner fuels (like natural gas). Under current policy, fuels compete on their energy content, not on their cleanliness. If the nation is to solve its pollution problems, environmental consequences should become a major consideration in individual and corporate fuel selection.

2. Reform of the Public Utility Holding Company Act is needed to allow gas-fired powerplants built by independent power producers (IPPs) to provide competitively priced electricity to the nation's consumers. Gas-fired facilities are faster to build, more efficient, and more environmentally acceptable than competing technologies.

3. In the gas market itself, the regulators and industry participants should support new forms of long term contracting. An excessive reliance on the spot market has contributed to depressed prices and depressed drilling activity. Specifically, we must reform the merchant function of natural gas pipelines to:

    - restore mutuality of contract;
    - relieve pipelines of service obligations where there is no mutuality; or,
    - deregulate the merchant function.

    Local Distribution Companies (LDCs) can act on their own today and in the near term to assure supply during the forthcoming tight period by signing long term supply contracts. Private parties can structure deals to give producers incentives to drill today for the longer term supply needs of the customers. But, State Public Utility Commissions must encourage a balance between supply security and "least cost" purchasing policies by LDCs. Too often in a surplus market, least cost purchasing policies have led to an excessive reliance on spot gas to serve the LDC's firm residential market. As the gas market becomes supply constrained, security of supply should become an increasingly important factor in LDC's gas purchase decisions.

4. The Congress should reconsider drilling incentives. While broad based drilling incentives are less distortive, targeted incentives such as a tax credit for coal seam and tight sands gas are less costly to the Treasury. The supply response shown in the low drilling

cost case suggests that this type of initiative would produce a significant supply response.

There are three broad policy implications of our supply evaluation:

1. The legislative and regulatory reforms of the last decade (wellhead decontrol, open access), make it very unlikely that the nation will experience gas shortages like we did in the 1970s.
2. Natural gas can and should play an important role in solving the nation's environmental and energy security problems. However, current policy does not recognize the major constructive contribution which natural gas can and must make.
3. Further reforms are needed to improve the functioning of the natural gas market and to complete the transition to a more competitive market. These reforms are important not only to the gas industry but are important to the nation if we are to solve our pressing environmental and energy security problems.

October 9, 1989

APPENDIX A

METHODOLOGY

Enron began its analysis of gas supply and demand realizing it had to examine natural gas in the broader context of the total U.S. energy market. This required an analytical framework, or modeling system, for determining the market equilibrium for all forms of energy over a wide range of scenarios. Of the several such systems available, we chose the Energy and Environmental Analysis, Inc. (EEA) Energy Overview Model which has three major components: (1) the Hydrocarbon Supply Model; (2) the Pipeline Flowing Gas Model; and (3) the End-Use Sector Demand Models.

The Energy Overview Model solves for gas consumption and production, gas prices and drilling activity over time given inputs of crude oil prices, alternate fuel prices, the Lower-48 hydrocarbon resource base, regulatory environment, economic growth, etc. A virtue of the EEA modeling system is the control it allows a user over all key assumptions and model parameters. This was important since Enron wanted to fold into the analysis its knowledge and understanding of the oil and gas businesses. Enron used a panel of reservoir engineers, geologists, economists, and gas marketers to check the key model parameters and develop the input assumptions for each scenario.

A second virtue of the EEA modeling system is the power of EEA's Hydrocarbon Supply Model--a rigorous, computer-based framework for analyzing the resource cost of finding, developing and producing natural gas and crude oil in the Lower-48 United States. The model and its supporting databases were developed for the Gas Research Institute in the early 1980s at a cost of over a million dollars. The databases contain information on all oil and gas fields found in the Lower-48 (outside Appalachia) through 1985--over 35,000 fields, as well as information on individual exploratory and gas wells and extensive data on leasing, drilling, equipping and operating costs.

A. The Hydrocarbon Supply Model--What It Does

The Hydrocarbon Supply Model is designed to simulate the exploration, development and production of crude oil, natural gas and natural gas liquids. It utilizes of a highly disaggregated characterization of the undiscovered resource base--14 supply regions, 4 depth intervals and 20 field sizes. The resource base is further characterized as crude oil, NGLs, associated gas, conventional nonassociated gas, tight gas, Devonian shale, coalbed methane, etc. Cost algorithms linked to each element of the resource base allow the model to capture:

- exploratory and development costs per unit by supply region and depth
- economies of scale in field development
- the concept of what is "found" versus an economic find
- improvements of the efficiency of the discovery process

The model permits the explicit simulation of decision making by producers and pipelines. Producer investment decisions consider:

- expected oil and gas prices and gas market conditions
- expected hydrocarbon discoveries
- cost of lease acquisition, drilling, equipping and producing
- capital constraints on exploration and development expenditures
- behavioral constraints on redirecting ED&P activity

The basis of the producer decision logic is discounted cash flow analysis of investment options using expected oil and gas prices. At the election of the user these expected prices can differ from the model's solution prices thereby simulating the common tendency to use current prices or an extrapolation of recent price trends to make investment decisions. The typical capital constraint is to limit exploration and expenditures to previous periods net cash flow. The behavioral constraints prevent an instant redirection of all expenditures to the region with the "best" resource economics. This accounts for differing perceptions of relative resource costs and the difficulty firms face in establishing lease positions, geological knowledge and organizations in new areas.

Development and production decisions are also influenced by pipeline behavior including: pipeline reserve acquisition strategies and contracting practices; and pipeline take strategies. Pipeline and producer behavior are allowed to interact to produce a realistic portrayal of industry behavior.

The ease with which a user can specify alternate behavioral and material parameters makes the Hydrocarbon Supply Model a powerful tool for assessing uncertainty. One can change the size of the resource base, model different producer and pipeline behaviors, adjust interest rates and drilling cost trends, and evaluate the effects of alternate price forecasts, take rates and other market conditions.

B. The Hydrocarbon Supply Model–How It Works

The key feature of any oil and gas supply model is its representation of how exploratory activity leads to discovery. This is typically modeled through find-rate equations which give discoveries as a function of activity (footage drilled, well completions, dollars spent, etc.). Activity is in turn a function of price and/or expected profitability.

The most common approach is to use reserves per foot equations to relate total drilling activity in a large area, say Lower-48 onshore, to total discoveries (and sometimes total reserve additions) in that area. This approach has some obvious drawbacks:

(1) it ignores the fact that costs per foot increase with depth;

(2) it fails to capture economies of scale in field development since field size is ignored; and

(3) it cannot deal with the concept of what is "found" versus what is not only found but developed and booked as proved reserves.

EEA overcomes these problems by:

(1) disaggregating the resource base by region and depth;

(2) using field size distributions;

(3) explicitly modeling the development decision (treating exploratory costs as sunk);

(4) booking only profitable fields as proven reserves; and

(5) banking unprofitable finds until economics improve.

The fundamental theory behind EEA's approach is that big fields are easier to find and cheaper to develop than small fields. EEA uses a "double exponential" find-rate equation to predict the number of fields of each that will be found for a given number of exploratory wells. In any given supply region large fields are more likely to be found in the earlier stages of drilling. In the later stages of the exploration process only medium and small fields are found.

For regions/depth intervals in which substantial drilling has taken place, the find-rate equations are determined by statistically fitting the equations to actual discoveries. For regions/depth intervals with insufficient drilling history, the parameters for the find-rate equations are estimated by analogy to mature areas.

C. The Hydrocarbon Supply Model Lag Structure

Exploration and production is a long lead time business. It can easily take 2-4 years onshore, and 5-10 years offshore, to advance from preliminary geological and geophysical work to initial production. And, the typical large new field will not reach peak production for several more years. Thus, it takes the industry a long time to completely respond to a change in oil and gas prices.

The Hydrocarbon Supply Model is designed to realistically portray the physical aspect of the E&P business. This portrayal, in combination with the model's capital and behavioral constraints, imposes a lag structure that mimics the lagged response of the E&P business to a price change.

D. Pipeline/Flowing Gas Model

The Pipeline/Flowing Gas Model represents the U.S. gas transmission and distribution network through 12 composite pipeline systems and 10 composite distribution companies. These pipeline systems link the 14 Hydrocarbon Supply Model regions to 10 demand regions within which citygate and end-use gas prices are calculated.

The model tracks the supply status for each pipeline system, including reserve dedication, deliverability, pricing and other contract terms. The model uses transmission and distribution rates specific to each pipeline group. These rates have fixed and variable components and are throughput sensitive (i.e., average cost per unit is higher at lower throughputs). The user can specify the rate design methodology and degree of rate discounting, if any. For our analysis, Enron specified modified fixed-variable rate design and allowed discounting for carriage gas volumes.

E. End-Use Sector Models

The EEA family of end-use demand models includes: (1) the Residential/Commercial Demand Model; (2) the Industrial Gas Demand Model; and (3) the Electric Utility Model. These models project energy demand and simulate fuel choice decisions. Each is disaggregated by region (10 Federal regions) and energy uses.

The **Residential/Commercial Demand Model** represents 23 building and use types. Fuel and technology choice decisions consider climatic differences, consumer behavior, relative fuel prices and the efficiency, initial cost and useful life of competing end-use technologies. New construction is evaluated separately from existing buildings.

The **Industrial Gas Demand Model** characterizes combustors in 9 major industry groups and 50 specific functional uses (e.g., boilers, glass melters, steel reheat furnaces, etc.). The model's decision logic is based on life cycle cost minimization. Technical constraints and environmental requirements are considered in the economic analysis of fuel choice decisions. The model is supported by extensive databases on the number, size, efficiency, utilization rates and operating costs of industrial combustors.

For both of the above end-use models, the primary driver of energy demand is expected economic activity including demographic trends, GNP growth and specific industry growth rates. The user can obtain a consistent set of these trends from an economic forecasting service.

The **Electric Utility Model** handles 23 powerplant types and three modes of operation: base load, cycling and peaking. Plant operating rate and fuel consumption is determined by an economic dispatch algorithm. The model also produces electricity prices used in the Residential/Commercial and Industrial Gas Demand Models. The user can specify the demand for electricity or allow it to be determined by the other end-use sector models.

Utility sector fuel switching is decided on a least-cost basis with the residual fuel oil type determined by environmental regulations. The types of powerplants entering service are input by the user (the model uses economics to decide which plants operate, but not to decide which plants are built). Typically one uses the National Electric Reliability Council's (NERC) published plant construction plans as the starting point. These plans can then be modified to reflect the user's beliefs about the timing and type of new powerplants.

ADDITIONAL DATA

COMPARISON OF LOWER-48 RESOURCE BASE ASSUMPTIONS
(TCF)

CATEGORY	ENRON TOTAL	ENRON @ $3.00 BASE[1]	ENRON @ $3.00 FLAT COSTS	DOE TOTAL	DOE @ $3.00	1988 PGC
New Fields	366.5	40.1	105.0	353.0	142.0	423.3
Old Field Apprec.	155.7[3]	85.4	123.2	108.0	108.0	155.8[3]
Non-Assoc. Infill	21.0	8.1	12.8	119.0	56.0	--
Devonian Shale	26.2	6.5	7.7	31.0	10.0	8.7
Coalbed Methane	47.1	9.0	25.4	48.0	8.0	90.1
Associated Gas from Oil Infill	17.2	9.4	14.0	61.0	30.0	--
Low permeability	--[2]	--[2]	--[2]	180.0	70.0	--[2]
Wyo. Low BTU Gas	13.0	0.0	4.5	--	--	--
	646.7	158.5	292.6	900.0	424.0	677.9

(1) Enron's cost estimate includes all finding and developing costs including real escalation of drilling costs by 50% by 2000. DOE's cost estimate appears to use current drilling costs and may exclude development costs. The flat cost case assumes no real cost increase, which is more comparable to EIA

(2) Some low permeability gas included in new and old fields.

(3) Includes Appalachian tight.

Natural Gas Resource Base as of 12/31/86, Tcf

	Enron 1989	PGC 1988	DOE 1988
A. By Region			
Atlantic	78	77	na
North Central	8	19	na
Gulf Coast	221	204	na
Mid-Continent	138	139	na
Rocky Mountains	131	120	na
Pacific	24	30	na
Subtotal	600	588	852
Coalbed Methane	47	90	48
Total Lower 48 Resources	647	678	900
B. By Type of Resource			
New Field Resources	367	423	353
Old Field Reserve Growth			
Inferred/Probable, Nonassociated	134	na	108
Growth Due to Gas Infill Drilling	21	na	119
Inferred/Probable, Associated	22	na	na
Growth Due to Oil Infill Drilling	17	na	61
Total Reserve Growth	194	165	288
Coalbed Methane	47	90	48
Devonian Shale	26	na *	31
Tight Gas	na *	na *	180
Low Btu Gas	13	na	na
Total Lower 48 Resources	647	678	900

* Included in new field discoveries and old field appreciation

CURRENT POLICY CASE
LOWER- 48 NATURAL GAS BALANCE (1)
TCF

DEMAND	1987	1990	1995	2000
INDUSTRIAL(2)	5.6	5.9	5.7	6.1
POWERPLANTS(3)	3.1	3.0	3.4	3.9
RESIDENTIAL/COMMERCIAL	6.7	6.8	6.6	6.5
OTHER(4)	1.9	1.9	1.9	2.0
TOTAL DEMAND	17.3	17.5	17.6	18.4
SUPPLY				
LOWER-48 PRODUCTION	16.1	15.7	15.3	15.9
CANADIAN IMPORTS	0.9	1.3	1.7	1.9
LNG+SNG+SUPPL.	0.1	0.3	0.5	0.8
TOTAL SUPPLY	17.2	17.3	17.5	18.6

(1) Excludes .3 Tcf of Alaskan Production and Consumption. Totals do not add due to model convergence.
(2) Includes feedstock.
(3) Includes electric utility and cogeneration uses.
(4) Includes EOR, gas treating, liquids processing, and pipeline compressor fuel.

LOW OIL PRICE CASE
LOWER- 48 NATURAL GAS BALANCE (1)
TCF

	1987	1990	1995	2000
DEMAND				
INDUSTRIAL(2)	5.6	5.9	5.6	5.0
POWERPLANTS(3)	3.1	3.0	3.1	3.3
RESIDENTIAL/COMMERCIAL	6.7	6.8	6.6	6.5
OTHER(4)	1.9	1.9	1.8	1.7
TOTAL DEMAND	17.4	17.6	17.1	16.5
SUPPLY				
LOWER-48 PRODUCTION	16.1	15.7	15.0	13.9
CANADIAN IMPORTS	0.9	1.3	1.7	1.8
LNG+SNG+SUPPL.	0.1	0.3	0.5	0.8
TOTAL SUPPLY	17.2	17.3	17.2	16.5

(1) Excludes .3 Tcf of Alaskan Production and Consumption. Totals do not add due to model convergence.
(2) Includes feedstock.
(3) Includes electric utility and cogeneration uses.
(4) Includes EOR, gas treating, liquids processing, and pipeline compressor fuel.

LOW DRILLING COSTS CASE
LOWER- 48 NATURAL GAS BALANCE (1)
TCF

	1987	1990	1995	2000
DEMAND				
INDUSTRIAL(2)	5.7	6.1	6.1	7.4
POWERPLANTS(3)	3.0	3.0	3.7	4.7
RESIDENTIAL/COMMERCIAL	7.1	6.8	6.8	6.8
OTHER(4)	2.0	2.0	2.0	2.3
TOTAL DEMAND	17.8	17.8	18.4	21.0
SUPPLY				
LOWER-48 PRODUCTION	16.2	15.8	16.2	18.2
CANADIAN IMPORTS	1.3	1.4	1.7	1.9
LNG+SNG+SUPPL.	0.2	0.3	0.5	0.8
TOTAL SUPPLY	17.7	17.5	18.4	21.0

(1) Excludes .3 Tcf of Alaskan Production and Consumption. Totals do not add due to model convergence.
(2) Includes feedstock.
(3) Includes electric utility and cogeneration uses.
(4) Includes EOR, gas treating, liquids processing, and pipeline compressor fuel.

CMA
CHEMICAL MANUFACTURERS ASSOCIATION

January 4, 1989

Mr. Donald Santa, Jr.
Senate Committee on Energy and
 Natural Resources
364 Senate Dirksen Building
Washington, D.C. 20510-6150

Dear Mr. Santa,

As I promised during our telephone conversation today, I'm transmitting herewith a corrected version of a CMA statement for inclusion in the record of your recent hearings.

Thanks for your cooperation.

Sincerely,

Thomas Parker, Jr.

Thomas Parker, Jr.

2501 M Street, NW, Washington, DC 20037 202-887-1100 Telex 89617 (CMA WSH)

Comments of the Chemical Manufacturers Association
Natural Gas Supply and Artificial Demand

Proposals to promote the use of natural gas as a means of addressing this nation's environmental problems have been raised in recent policy discussions. It is argued that such action will improve environmental quality by substituting a cleaner burning fuel for other fossil fuels. Hand in hand with this argument is a perception that the U.S. resource base for natural gas is large, and that laws and regulations promoting natural gas consumption will resolve the problems associated with developing this resource base.

Increasing the supply of natural gas is a laudable goal, especially in the current environment where exploration activity remains low, proved reserves continue to decline and demand continues to grow. Policies that increase the supply of natural gas should be encouraged.

Policies that artificially promote the use of natural gas, however, would be counterproductive. Suggested policies of concern include mandating natural gas use and other non-market mechanisms that provide a bias for natural gas relative to other fuels.

This issue is of crucial interest to the Chemical Manufacturers Association (CMA). CMA is a nonprofit trade association whose member companies represent approximately 90 percent of the productive capacity of basic industrial chemicals in the United States and Canada. The U.S. chemical industry supplies a number of vital products, including those required for the manufacture of plastics, fertilizers, textiles, tires, paints, coatings, and a host of industrial and consumer goods. In 1988, the chemical industry employed about 1 million people domestically and had a positive trade balance of $12.4 billion dollars.

The U.S. chemical industry is highly energy intensive and relies on natural gas supplies for feedstock and fuel. The industry accounts for about 10 percent of total U.S. natural gas consumption and over 25 percent of industrial gas consumption, making it the nation's largest industrial natural gas user. Thus, access to adequate natural gas supplies at competitive costs is essential to the chemical industry's economic viability, and is a paramount objective for CMA member companies.

Current Natural Gas Reserves and U.S. Demand Patterns Indicate a Natural Gas Supply/Demand Imbalance.

Current U.S. natural gas supplies give reason for caution as natural gas is discussed in an environmental context. Proved reserves in the lower 48 states have been declining at alarming rates in recent years. Proved reserves at the beginning of 1971 were about 260 trillion cubic feet, as compared to 154 trillion cubic feet at the beginning of 1988. This represents a 41 percent decline over a 17-year period. (Even Canadian reserves, the source of most imported natural gas into the United States, are declining according to a recent Canadian Petroleum Association report.) CMA believes efforts to reverse the decline in U.S. reserves are badly needed to ensure adequate future natural gas supplies to meet current and projected needs.

Since 1981, the number of producing gas wells completed has also been on the decline. Producing wells completed in 1987 totalled only 7,200, less than half the 1981 level of 18,400. Completed exploratory wells were 21 percent of completed producing wells in 1974, but fell to only 12 percent by 1984, and have remained virtually constant at this level for the last five years.

As a result, additions to proved reserves in 1987 for the top forty U.S. gas reserve-holding companies amounted to only 70% of production. Although some reports have 1988 replacement levels as high as 130% it must be noted that much of this replacement resulted from a high level of "revisions", and that new discoveries during 1988 represented only about 60% of production.

Meanwhile, U.S. natural gas consumption has been on the increase. Over the past three years demand rose 14.2 percent, climbing to 18.5 trillion cubic feet during 1988 as compared to the 1986 low of 16.2 trillion cubic feet. Consumption of natural gas increased more than any other fuel between 1987 and 1988 (5 percent), and if the outlook for the U.S. economy remains strong, demand is likely to continue to rise.

In fact, demand is increasing more rapidly than production. According to the latest Energy Information Administration figures, 1988 production increased only 0.6 percent to 16.6 trillion cubic feet, although consumption was considerably higher at 18.5 trillion cubic feet. This difference, met largely via Canadian imports, strongly suggests a need to increase U.S. natural gas production. Increased natural gas production not only would serve to better maintain pace with rising demand, but also would result in a corresponding increase in the production of natural gas liquids, an important source of feedstock for the U.S. chemical industry and the precursor to vast numbers of consumer goods.

Energy Policies Should Include Consideration of Their Environmental Impact, But Consumer Choices Should Not Be Dictated.

It is widely understood that some energy management practices may have an adverse effect on the environment. A range of options are available to address these potential impacts, including such measures as improved efficiency and conservation, development of new technologies, and fuel switching. CMA believes that, as these broad areas are pursued with energy and environmental goals in mind, government policies should not dictate the choices available to consumers. Rather, the selection of specific options should be based on the merits of each option as determined in the marketplace.

Increased natural gas use is one option that should be considered on its own merits vis-a-vis other energy options. The marketplace should determine whether this is a preferred option, however, because any artificial promotion or mandated natural gas use could have a negative effect: tightening supply, raising prices, limiting interfuel competition, reducing available capacity of existing distribution systems, and damaging U.S. industrial competitiveness in world markets. Energy intensive industries such as petrochemical and related derivative producers simply cannot compete effectively in world markets without competitive energy costs.

Natural Gas Supply Should Be Promoted So That Natural Gas Can Compete With Other Fuels On Its Own Merits.

Recognizing that the use of natural gas in place of other fossil fuels could be an option for addressing environmental concerns, CMA supports actions which encourage increased supply and availability of natural gas. Many steps have already been taken which should have a positive impact on supply. These include open-access natural gas transportation, access to Canadian imports, and decontrol of wellhead natural gas prices. Further actions to increase availability and access to supplies, such as pipeline rate reform and responsible exploration and production in environmentally sensitive areas, also merit consideration. Actions and policies which lead toward increased supply of natural gas in and of themselves promote, through market forces, use of natural gas as an alternate to other fuels.

Mandated use of natural gas to address environmental concerns should be avoided. Mandating natural gas use will create distortions in the marketplace and in natural gas distribution systems, and will adversely affect industrial competitiveness. Finally, mandated use of natural gas is unwarranted. By opening access to transportation, encouraging additional supplies, and encouraging competition, natural gas use will increase. A market driven approach is the most efficient way of achieving increased natural gas utilization for the benefit of both the environment and the economy.

References:

1. Natural Gas Trends, Arthur Anderson & Company / Cambridge Research Associates, 1988-89 Edition.

2. "Putting the U.S. Gas Industry Back Together After the Bubble", John C. Sawhill, Director, McKinsey & Company Inc., Oil & Gas Journal, August 28, 1989.

3. Energy Information Administration Statistics, Monthly Energy Review, December, 1988, page 27.

10/27/89

SOUTHERN CALIFORNIA gas COMPANY
1150 CONNECTICUT AVENUE, N. W., SUITE 717
WASHINGTON, D. C. 20036 • (202) 822-3713

DAVID W. FREER, Manager
Federal Governmental Affairs

October 17, 1989

Mr. Don Santa
Counsel
Mineral Resources Development and
Production Subcommittee
Senate Energy and Natural Resources
Committee
SD-362 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Don:

Please find enclosed SoCalGas Company's statement for the hearing record of the oversight hearing on Gas Supply and Deliverability, held September 26, 1989.

We appreciate your consideration of our statement.

Sincerely,

David W. Freer

DWF/rem
Enclosure

STATEMENT OF SOUTHERN CALIFORNIA GAS COMPANY
BEFORE THE
SUBCOMMITTEE ON MINERAL RESOURCES DEVELOPMENT AND PRODUCTION
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
OVERSIGHT HEARING ON GAS SUPPLY AND DELIVERABILITY
SEPTEMBER 26, 1989

As the largest and one of the fastest growing natural gas distribution utilities in the United States, Southern California Gas Company (SoCalGas) has a direct and compelling interest in gas supply and deliverability, the subject of this oversight hearing.

Projected Market Growth

We believe that the demand for natural gas in our service territory--which encompasses a population of more than 14 million within 23,000 square miles of Southern and Central California--will continue to grow in the 1990s and beyond. While population growth in the SoCalGas service area is projected at a compound annual rate of 1.3 percent in the next 20 years, the number of residential meters served by SoCalGas is expected to increase by an average of 80,000 per year. Total natural gas requirements are expected to expand from nearly 1 trillion cubic feet this year to some 1.3 trillion cubic feet or more by the year 2010.

The public's strong desire for improved air quality in Southern California--currently considered the worst in the nation--will spur much of the higher demand for natural gas as an energy source in the years ahead. Air quality considerations will be a major factor in the anticipated construction of new gas-fired generating capacity to meet an anticipated higher growth rate in the demand for electricity. In addition, natural gas-fueled vehicles, or NGVs, are expected to be a new and potentially significant market for natural gas, the cleanest burning of all fossil fuels. Other major market sectors projected to show substantial growth in natural gas use during the next 20 years are Enhanced Oil Recovery (EOR) and related cogeneration, industrial and commercial cogeneration. Future demand in the residential and small commercial markets will be moderated somewhat by continued improvements in efficiency, such as application of tighter building standards and appliances which use less energy.

Despite the anticipated growth, SoCalGas believes that the gas supply outlook over the next 20 years is favorable. Adequate supplies over the entire period are expected to be available from a variety of sources, including California onshore and offshore gas; dedicated gas from traditional pipeline suppliers;

gas released by these pipeline suppliers; future reserve additions in traditional supply areas; spot market gas; supplemental supplies from Canada, the Rocky Mountains, Mexico and new offshore development; and the transportation of customer-owned gas.

One of the biggest challenges facing SoCalGas and its suppliers over the next 20 years, however, will be to develop the most efficient and economical ways to bring the additional gas needed to Southern California. There is no lack of interest among gas producers, pipeline companies, distributors and brokers to serve the Southern California market. For example, numerous proposals to construct new interstate pipelines to Southern California are currently under active consideration by the Federal Energy Regulatory Commission (FERC).

Air Quality

SoCalGas believes that improving air quality is one of the most pressing environmental issues facing our nation. We support fair and reasonable amendments to the Clean Air Act to assist regions throughout the country in meeting federal clean air standards.

The heart of Southern California's air pollution problem is mobile source emissions. According to the South Coast Air Quality Management District (SCAQMD), the local air quality planning agency, mobile sources such as trucks, cars and buses contribute well over half of the emissions that cause ozone, one of the most troublesome problems in Southern California. Mobile sources also contribute over 90 percent of all carbon monoxide emissions, another dangerous pollutant. If severe non-attainment regions such as Southern California are to achieve the reductions necessary to clean up the air, mobile source emissions must be stringently controlled.

NGVs can play an important role in helping to solve Southern Callifornia's air quality problems--if compressed natural gas (CNG) is given a reasonable opportunity to compete with other alternative vehicle fuels. CNG is particularly well suited as a fuel for fleet vehicles and urban buses which operate within a defined area and return to a central location. According to the Environmental Protection Agency, NGVs have the potential to reduce emissions which form ozone by over 65 percent, and to reduce carbon monoxide emissions by over 90 percent from the current emissions levels of gasoline and diesel vehicles.

The SCAQMD recently adopted a 20-year plan to clean up the region's air. Ultimately, this plan will require that 40 percent of the cars, 70 percent of the trucks, and all diesel buses in the region use an extremely low emitting energy source such as natural gas, methanol or propane.

Increased use of natural gas as a transportation fuel could significantly boost demand for the fuel in the SoCalGas service area. For example, annual gas usage could increase by 50 Bcf if natural gas were the the exclusive fuel for achieving the local air quality plan goal of converting 70 percent of fleet vehicles to alternate fuels. Converting all buses operated by transit districts in the Los Angeles area to CNG could increase gas sales by an additional 7 Bcf per year. If private automobiles were converted to natural gas on a large scale, gas demand would increase by 75 Bcf per year for each one million vehicles. While conversions on this scale are unlikely in the near future, these figures illustrate a potential major new market for natural gas in Southern California.

An estimated 30,000 NGVs currently operate in the United States. These vehicles are supported by 300 private refueling stations and 13 public stations. Virtually all of these NGVs have been converted from vehicles designed to use gasoline or diesel fuel. The costs of converting passenger cars to use natural gas range from about $1500 to $3000, while medium and heavy duty truck and transit bus conversion costs are much higher. Costs could be reduced substantially, however, if increased demand for NGVs stimulated auto, truck and bus manufacturers to mass produce natural gas-dedicated vehicles.

The clean emissions characteristics, cost effectiveness and availability of natural gas make it an attractive vehicle fuel. A lead-free fuel, natural gas produces virtually no carbon monoxide, sulfur oxides, or particulates and low levels of other pollutants. NGVs meet all EPA emissions standards. The relative absence of impurities in natural gas can help reduce engine wear, increase spark plug life and more than double the interval between oil changes. Natural gas is 30 to 60 percent less expensive (including the cost of compression) than gasoline. The gallon equivalent price of natural gas ranges from 40 cents to 75 cents.

Research and development will play a key role in determining the rate at which NGVs are converted and deployed in the future. Accordingly, SoCalGas has undertaken a major effort to develop and explore the commercialization of NGV technology. In addition to supporting the NGV research and development projects of the Gas Research Institute, we are directly involved in the research, demonstration and field testing of NGVs. These efforts include a joint program with the Southern California Rapid Transit District that will operate 10 natural gas buses in the San Fernando Valley.

Environmentalists, consumer groups, regulators and legislators are beginning to recognize the benefits of NGVs and the use of CNG as an alternate fuel that can help clean up the air. But meaningful progress will depend to a great extent on the support and encouragement of federal, state and local government. Additional funding is needed for research and development, as well as financial incentives for the use of NGVs.

Pipeline Expansion

The need for new pipeline capacity to serve the growing Southern California natural gas market was foreshadowed by the emergence of the EOR market in the early 1980s and the subsequent development of proposals for new interstate pipelines to serve that market. The EOR market has been called the fastest growing gas market in the U.S., with potential demand ranging from 600 MMcfd to 1 Bcfd. SoCalGas currently has contracts for serving approximately 600 MMcfd of this market. Further impetus for additional pipeline capacity also has been provided by the increased public concern for improving air quality in Southern California and spot curtailments of noncore (primarily large industrial and electric utility) customers in Southern California in recent years.

In December 1988, the California Public Utilities Commission (CPUC) initiated an investigation to determine the need for additional interstate natural gas pipeline capacity to serve California. In February 1989, the CPUC declared that there is a need for a higher level of service--and potentially an increase in pipeline capacity--for large noncore customers. The CPUC directed the California gas utilities to meet with pipeline proponents and other interested parties and to seek agreements on constructing new pipeline capacity which meets specific criteria established by the Commission. The CPUC is currently examining the settlement agreements submitted by the parties and expects to issue a final decision in this proceeding by the end of 1989.

As part of its strategy to respond to the need for a higher level of service for its customers, SoCalGas plans to expand its southern pipeline system from the California/Arizona border to Los Angeles. This project (in conjunction with a planned expansion of an existing interstate pipeline operated by El Paso Natural Gas Company) will increase pipeline capacity by 200 MMcfd, as well as improve gas storage efficiency and the operational flexibility of the SoCalGas system. The Southern System Expansion can be completed by the fourth quarter of 1990--assuming timely regulatory approvals. It is not directly competitive with proposed interstate pipeline projects.

SoCalGas projects that there will be a demand for between 700 MMcfd and 1.1 Bcfd of additional interstate pipeline capacity by the year 2010 to serve Southern California. In anticipation of serving this huge market, two consortiums have developed proposals for new pipelines to Canada, two are seeking permission to build pipelines from Wyoming and the Rocky Mountains, and another partnership wants to construct a pipeline to deliver additional gas from the Southwest. Two of these initial proposals have been granted optional certificates for construction by the FERC. They are being modified, however, and will be under active consideration by the FERC along with the other pending interstate pipeline projects.

SoCalGas supports and has signed agreements with the sponsors of three proposed interstate pipelines that together would form a new integrated pipeline system bringing gas to Southern California from Canada, the Rocky Mountains and the Southwest. (See attached map.) These proposals are known as the Altamont Gas Transmission Project (Altamont), the Kern River Gas Transmission Company (Kern River), and the Mojave Pipeline Company Project (Mojave).

The Altamont pipeline would access plentiful gas supplies in Alberta, Canada, and bring them to California through an entirely new route. It would extend some 620 miles from the U.S./Canadian border near Wild Horse, Montana, to Opal, Wyoming, where it would interconnect with the Kern River pipeline. SoCalGas has the rights to acquire capacity of 200 MMcfd on the Altamont system.

The Kern River pipeline would be built from Opal, Wyoming to Southern California. Kern River would open up a whole new supply region--the Rocky Mountain "Overthrust Belt"--to California gas users. It also would provide access to substantial volumes of competitively priced Canadian gas. SoCalGas has acquired the rights to a total of 200 MMcfd of firm capacity on the Kern River System, as well as the right to purchase the California facilities of Kern River after 20 years.

The Mojave pipeline would originate in Topock, Arizona, near the California border. It would provide California markets with additional access to gas-producing regions in the Southwestern states.

SoCalGas believes that the Altamont-Kern River-Mojave pipeline network offers the most complete package of services and options to meet the long-term needs of the dynamic and growing Southern California natural gas market. This network provides direct access, via an integrated system, to a greater diversity of gas sources than any other proposal. It offers new and efficient routes for the transportation of Canadian and Rocky Mountain gas and increased access to Southwest U.S. supplies, including New Mexico coal seam gas.

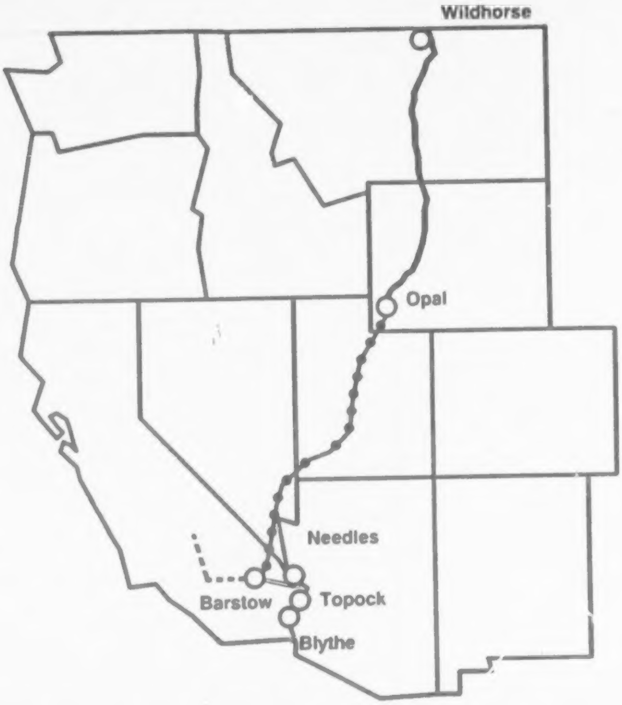
Remaining Regulatory Decisions

Recognizing the need for additional pipeline capacity to meet the state's growing natural gas requirements, the California Legislature recently declared that it is state policy to support and encourage the issuance of permits for the construction of interstate pipeline facilities that comply with applicable laws regulating environmental quality.

The fate of the proposed interstate pipeline projects designed to serve California is now in the hands of state and federal regulatory agencies. The CPUC is expected to complete its review of the various proposals and submit its recommendation to the FERC by the end of the year. It will then be up to the FERC whether to accept the conditions requested by the CPUC to protect the interests of all California gas consumers and utilities, and to issue final permits for the construction of the projects.

Cooperation between the two regulatory agencies, appropriate allocation of costs and risks, and quick action by the FERC in issuing final construction approvals are all necessary if California's natural gas users are to benefit in the near future from increased pipeline capacity. Ultimately, the gas market itself will determine the amount of new interstate capacity that is constructed.

Pipelines under SoCalGas' settlements



Settlements SoCalGas has reached with the sponsors of three proposed new interstate pipelines -- Kern River, Mojave and Altamont -- create an integrated transportation network to economically provide increased pipeline capacity for California gas users. Due to these settlements, Californians also will be served by a wider scope of gas supply regions.

Proposed Pipelines

——— Altamont

-•-•- Kern River

—— Mojave

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